

PRIORITIES FOR THE FUTURE



E X P A N D



T R A N S F E R



I N T E G R A T E



F O C U S

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1

EXPAND
OIL SANDS

2

TRANSFER
EXPERTISE AND
TECHNOLOGY FROM
OIL SANDS TO NEW
BUSINESSES

3

INTEGRATE
DOWNSTREAM AND
UPSTREAM BUSINESSES

4

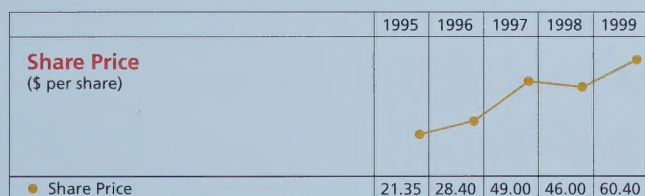
FOCUS
ON NATURAL GAS
AND ALTERNATIVE
AND RENEWABLE
ENERGY

Suncor Energy is growing. With a \$2-billion oil sands expansion in full swing and other growth plans in the works, the company's vision of the future has never been clearer.

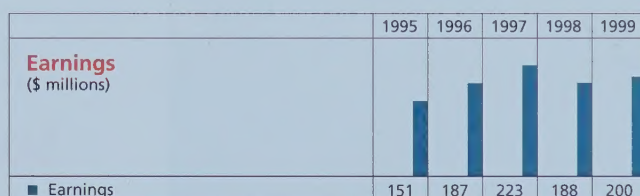
Financial Highlights

Year ended December 31 (\$ millions)	1999	1998	1997
Financial			
Revenues	2 387	2 070	2 154
Net earnings	200	188	223
Cash flow from operations	591	580	575
Capital and exploration expenditures	1 350	936	847
Total assets	5 176	4 104	3 457
Long-term borrowings	1 306	1 298	767
Dollars per Common Share			
Net earnings*	1.61	1.70	2.04
Cash flow from operations*	5.02	5.27	5.24
Cash dividends	0.68	0.68	0.68
Key Ratios – %			
Return on capital employed	8.8	9.9	14.8
Return on shareholders' equity	10.9	12.9	16.9
Debt/Debt plus shareholder's equity	38.5	46.4	36.6
Net debt/cash flow from operations (times)	2.3	2.2	1.4

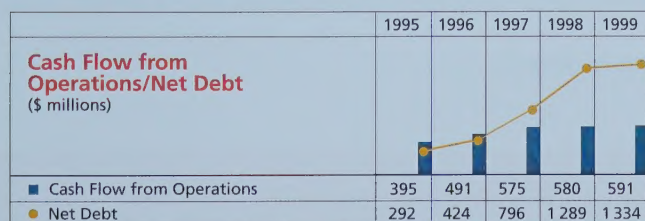
* Per share amounts for earnings and cash flow from operations reflect the payments on preferred securities issued in 1999.



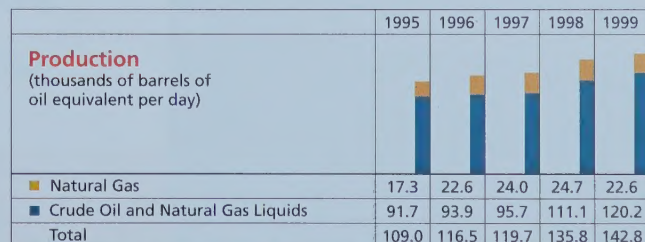
Suncor's 1999 year-end share price increased 31% over the 1998 year-end and 183% since 1995. In this same five-year period the integrated oil and gas index on the Toronto Stock Exchange (TSE) increased 85% while the TSE 300 increased 79%.



Earnings increase of 6% in 1999 reflects the benefit of higher commodity prices, increased sales volumes and asset divestments. These favourable factors were partially offset by crude oil hedging losses, higher costs and lower refining earnings.



Suncor's cash flow from operations increased for the seventh consecutive year. A preferred securities offering of \$514 million in 1999 minimized the increase in debt despite over \$1 billion in capital and exploration spending.



Production continues its upward trend for the ninth year in a row. Phase 2 of Project Millennium is under way to further increase oil sands production levels and there is an increasing emphasis on growing our natural gas production base.

Suncor Energy Inc.

is a growing Canada-based integrated energy company with \$5.2 billion in assets and production of 142,800 barrels of oil equivalent per day. The company has four key business areas:

Oil Sands

produces and markets custom-blended refinery feedstocks and transportation fuel from its oil sands mine and upgrading facility in Fort McMurray, Alberta, Canada.

Exploration and Production (E&P)

explores for, acquires, develops and produces natural gas and oil in Western Canada and markets its production throughout North America.

Sunoco

refines and markets petroleum products and chemicals with a major refinery in Sarnia, Ontario, a network of more than 500 retail gasoline outlets throughout the province and a new energy marketing business.

In-situ and International Oil

focuses on developing heavy oil and oil shale technologies that could provide Suncor with unique strategic advantages on a global basis.



"Suncor's biggest challenge is to balance the need for economic growth, social responsibility and environmental leadership. For us, that's what sustainable development is all about."

RICK GEORGE
President and Chief Executive Officer

"Project Millennium is the largest growth initiative that Suncor has ever undertaken. The potential benefits for Suncor – in production growth and earnings – are huge. For the Fort McMurray region, Alberta and Canada, it translates into hundreds of jobs and further economic growth."



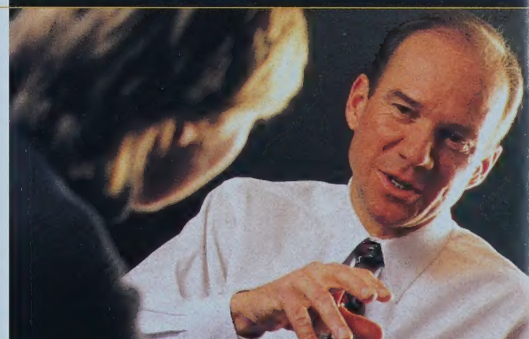
MIKE ASHAR,
Executive Vice President, Oil Sands

"In 2000 we will be looking for ways to improve financial performance and define new and profitable opportunities for growth. We will also be divesting crude oil assets to sharpen our focus on natural gas and generate cash to fund oil sands growth."



DAVE BYLER,
Executive Vice President, Exploration and Production

"Sunoco enters the 21st century with a resourceful and resilient refining and retail marketing business, prepared to further broaden its energy products and services."



TOM RYLEY,
Executive Vice President, Sunoco

"In 2000 we will continue with the commissioning of Phase 1 of the Stuart Oil Shale Project. In the meantime we are pursuing other international mineable oil opportunities and planning a new in-situ heavy oil project that will further expand our Fort McMurray Oil Sands operation."



BARRY STEWART,
Executive Vice President, In-situ and International Oil

COMPANY PRIORITIES FOR LONG-TERM GROWTH:

Priority 1: Expand Oil Sands

Priority 2: Transfer expertise and technology from Oil Sands to new businesses

Priority 3: Integrate downstream and upstream businesses

Priority 4: Focus on natural gas and alternative and renewable energy

For more information on Suncor's priorities for growth, see pages 10-19

MILESTONES 1999	2000+ GOALS
- Achieved record production, averaging 105,600 barrels per day. The new Deepbank Mine had its first full year of operation and generated more than 50% of Oil Sands production in 1999. - Construction of the \$2-billion second phase of Project Millennium began. The project is designed to raise production to 225,000 barrels per day. - Enbridge Athabasca Pipeline opened, expanding Oil Sands' ability to ship products to new markets in North America, and TransAlta Energy Corporation agreed to build, own and operate a \$315-million cogeneration facility to meet a portion of the future energy needs at Oil Sands. - In early 2000 announced plans to invest \$300 million in a further expansion of Suncor's Fort McMurray upgrading facility to accommodate production from the proposed Firebag In-situ Oils Sands Project.	2000: Increase average production to 115,000 barrels per day with cash operating costs per barrel at \$11.50 compared to \$11.40 in 1999. 2001: Achieve successful start-up and commissioning of Project Millennium and average production of 130,000 barrels per day. 2002: Achieve production capacity of 225,000 barrels per day and average production of 210,000 barrels per day. (A plant turnaround, previously planned for 2001, is now scheduled for 2002 and will have an impact on production.) 2003: Increase average production to 225,000 barrels per day with cash cost of \$8.50 to \$9.50 per barrel. 2004: Bring in-situ project on stream and increase production to 260,000 barrels per day while keeping cash cost per barrel in the \$8.50 to \$9.50 range.
- Increased net cash flow by \$168 million through asset sales that increased earnings to \$43 million in 1999, up 72% from 1998. - Total proven reserves declined by 37 million BOE as a result of property dispositions, downward revisions of reserve estimates and 1999 production from existing wells. - Poor drilling results and higher drilling costs contributed to an increase in F&D costs, bringing the three-year average to \$11.40 per BOE. - Production declined 5,000 BOE per day in 1999 as a result of property dispositions combined with natural reservoir declines, disappointing drilling results and delays bringing new production on stream. - Advanced investigation into coal bed methane by acquiring petroleum exploration licences on 1.3 million acres in Australia and conducting exploratory drilling in Canada.	- Deliver positive net cash flow through sales of non-strategic assets, expense reduction programs and improved operational performance. - Conduct strategy study of E&P business to improve financial and operating performance of natural gas business and define new and profitable opportunities for growth. - Invest \$130 million in natural gas exploration and exploitation of properties in Western Canada with near-term cash flow potential. - Produce 30,000 BOE per day (this goal reflects impact of ongoing property sales). - Continue to evaluate coal bed methane as an emerging new energy source and an opportunity to reduce greenhouse gas concentrations in the atmosphere. - Continue to investigate options to reduce natural gas flaring.
- Generated earnings of \$31 million, compared with \$40 million in 1998. - Increased earnings in Retail Marketing to \$22 million compared with \$17 million in 1998 and achieved a 15% ROCE. Implemented initiatives to strengthen Sunoco brand and build loyalty among customers and retailers. - Achieved and went beyond voluntary greenhouse gas emissions reduction targets. 1999 emissions were 7% below 1990 levels – a 2% improvement over 1998. - Achieved ISO 14000 certification in 1999. Sunoco's refinery was the first refinery in Canada and the fourth in North America to have its environmental management system endorsed under this international standard of accreditation. - Signed nine-year contract with NOVA Chemicals (Canada) Ltd. to extend the 1998 agreement to optimize production at both companies' facilities in Sarnia, Ontario.	- Position Sunoco's refinery to be among the Best in Class in North America by 2002. (Goal was to achieve this by 2000 but has been changed because of a delay in the deregulation of Ontario's electric system.) - Achieve and sustain a minimum of 10% ROCE in all operating units in 2001. - Work to achieve Sunoco's vision as the neighbourhood choice for energy, comfort and convenience shopping in Ontario. - Broaden Sunoco's natural gas and home energy dealer network and prepare for deregulation of the electricity market in Ontario. - Position Sunoco to meet legislation limiting sulphur in gasoline.
- Completed construction of the Stuart Oil Shale Project demonstration plant near Gladstone in Queensland, Australia. - Began commissioning of Stuart Project, which was targeted for completion by the end of 1999 but has been extended into 2000. - Launched the planning and community consultation process and filed for regulatory approval for a commercial in-situ project near Suncor's operation in Fort McMurray, Alberta. - Pursued potential opportunities in mineable oil development, including preliminary discussions on potential oil shale projects in Jordan and Estonia.	- Begin preliminary engineering and community consultation on the \$450-million Firebag In-situ Oil Sands Project. - Complete commissioning of Stage 1 of the Stuart Oil Shale Project, achieving and sustaining reliable plant production. - Demonstrate the feasibility of the Alberta Taciuk Process as it relates to further stages of oil shale development. - Create the technological platform for continuing shale oil development in Australia and worldwide.

Earnings (percentage)



Oil Sands	70
Exploration and Production	17
Sunoco	13

Cash Flow Provided from Operations (percentage)

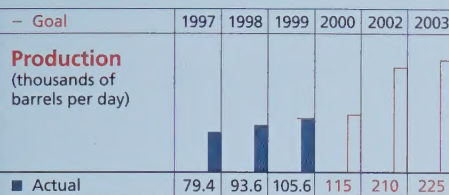


Oil Sands	60
Exploration and Production	25
Sunoco	15

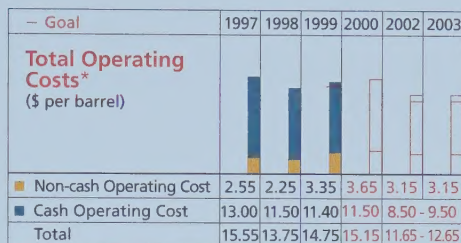
Capital Employed (percentage)



Oil Sands	55
Exploration and Production	29
Sunoco	16

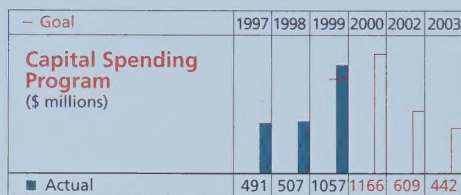


Oil Sands achieved its 1999 production goal of 105,000 barrels per day despite two unplanned production outages totalling approximately 16 days. Construction commenced on Phase 2 of Project Millennium, which is designed to increase production to 210,000 barrels per day in 2002 and 225,000 barrels per day in 2003.

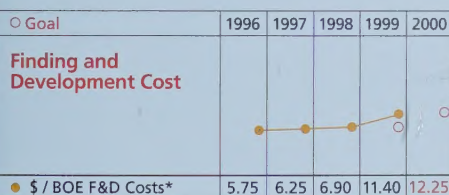


Total operating costs exceeded the 1999 goal primarily due to higher non-cash charges related to higher overburden costs.

* Total pre-tax expenses excluding royalties on the income statement expressed in terms of dollars per barrel of oil sold.

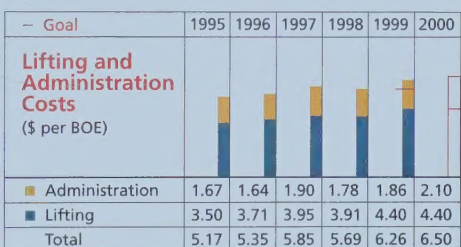


In the first quarter of 1999 Suncor received approval from its Board of Directors and provincial regulators to proceed with the \$2-billion Phase 2 of its Project Millennium expansion program. This project represented over 84% of Oil Sands' capital spending program in 1999.

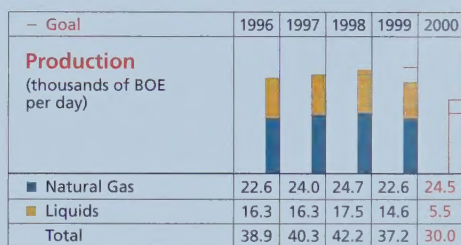


* Three-year rolling average proved reserve additions per barrels of oil equivalent (BOE).

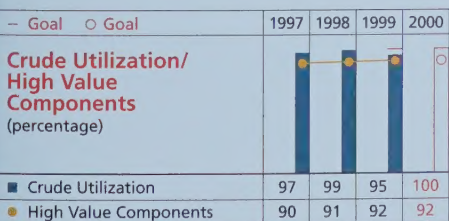
Disappointing finding and development program drives significant increase in F&D costs and pushes 3-year F&D cost to \$11.40 per BOE.



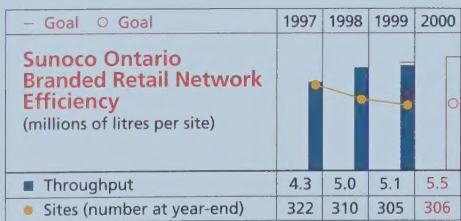
Production shortfall drives lifting and administration costs per BOE higher.



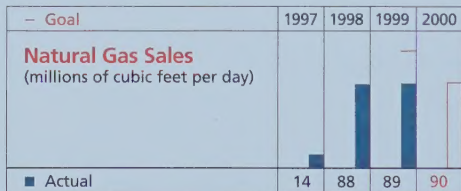
Property dispositions representing 3,300 BOE of annual production and poor drilling results negatively impact production volumes in 1999 and 2000 goals.



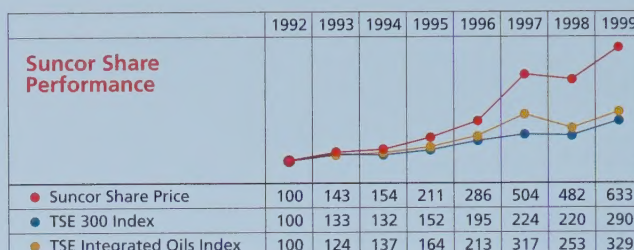
Crude utilization for the year was impacted by lower than planned first quarter distillate demands due to warm weather and fourth quarter operational outages. Some maintenance work planned for the first quarter of 2000 was brought forward to the fourth quarter of 1999.



Retail marketing initiatives supported the network efficiency growth. In 2000, expected increase in market demand, marketing initiatives and the impact of capital improvements are expected to improve site throughput.



In 1999, due to the competitive nature of the market and deregulation uncertainties, the business focus changed from aggressive customer acquisition to customer retention and marketing of product and services to customers.



This chart shows, as of December 31 in each of 1992, 1993, 1994, 1995, 1996, 1997, 1998 and 1999 the total cumulative return, assuming the reinvestment of dividends, of \$100 invested on December 31, 1992 in each of the Suncor common shares, the TSE 300 Composite Index and the TSE Integrated Oils Index.

Message to Shareholders

A Year of Achievements and Challenges

It has been a very busy year for all of us at Suncor Energy – a year full of great achievements and big challenges. We are now truly engaged in a program of aggressive growth that demands more from us than ever before.

During 1999 we began construction on the second phase of Project Millennium. This \$2-billion expansion of our oil sands operation is now in full swing, with new equipment arriving every day. At the peak of construction, nearly 3,000 workers will be putting it all together. The energy level at the site is amazing and, as the new facilities begin to take shape, so does Suncor's future.

At the same time, unexpectedly high oil prices have helped soften the blow of some disappointing operational results. We experienced two production disruptions at our Oil Sands plant, a less-than-satisfying year in our conventional Exploration and Production business, and a more difficult than anticipated commissioning of our Stuart Oil Shale Project in Australia. Through it all, Suncor employees are rising to the challenges, addressing the issues and leading the company into a successful future.

Suncor's 1999 Financial Performance

Earnings and cash flow in 1999 improved from our previous year, mainly due to a dramatic improvement in crude oil prices. Suncor's consolidated net earnings for the year were \$200 million compared with \$188 million in 1998. Cash flow from operations improved in 1999, rising to \$591 million, up from \$580 million in 1998.

Although we certainly benefited from higher crude prices in 1999, our hedging program reduced the average price we received by C\$2.15 per barrel. I believe it's a price worth paying to protect our earnings and capital spending program from the severe commodity price fluctuations. Just as we saw oil prices soar in 1999, we saw them plummet in the previous year. Our hedging program is designed to smooth these bumps by

reducing the impact of volatile oil prices on our cash flow and earnings, and I believe it has served our shareholders well.

Suncor's stock performance continued to reflect the confidence of our shareholders and the investment community. Suncor common shares closed at \$60.40 per share at the end of 1999, reflecting a 31% increase in value during the year and an increase of more than 600% since 1992. Suncor is one of 11 companies in the Toronto Stock Exchange's TSE 35 index that was able to increase its market value between 1998 and 1999.

Suncor's Operating Performance

Suncor faced several operating challenges during 1999. At our Oil Sands business, two unplanned outages at the upgrader facilities resulted in 16 lost days of production. Despite the outages, Oil Sands still managed to meet its average daily production target for the year, averaging 105,600 barrels per day – our seventh consecutive year of record-breaking oil sands production. Oil Sands cash operating costs were \$11.40 per barrel compared to \$11.50 per barrel last year.

Finding and development costs at our Exploration and Production business rose higher than our targets as a result of revised reserve estimates, poor drilling results and higher drilling costs. We have initiated a strategic review of this business to help get it back on a more competitive track. On the positive side, Exploration and Production increased net cash flow by almost \$170 million over last year on the strength of the sale of non-core properties in the Western Canada Sedimentary Basin, contributing to our cash flow requirements to support our Oil Sands expansion.

At our downstream arm, Sunoco, refinery margins remained under pressure for most of the year but other parts of Suncor's downstream business continued to strengthen. Retail marketing generated a 30% earnings increase in 1999 as a result of improved margins and higher ancillary sales of non-petroleum products and achieved a 15% return on capital employed.

"We aspire to be a sustainable energy company. That means applying the same kind of dedication to social and environmental performance as we do to economic performance."

MIKE O'BRIEN

Executive Vice President, Corporate Development and Chief Financial Officer



Oil Sands Growth Program On Track

Construction on our oil sands expansion, one of the largest construction projects in North America by a single company, began in the second quarter of 1999. Project Millennium is designed to more than double our oil sands production by 2003, while at the same time reducing our estimated cash costs to between \$8.50 and \$9.50 per barrel. In addition to increasing production and lowering unit costs, Millennium should also improve our overall reliability. When part of the process goes down for maintenance, its operating counterpart can continue to process oil. Although in some cases we would produce oil at a reduced rate during maintenance activities, the need for shutdowns of the entire plant will be virtually eliminated.

Oil Sands production is targeted to rise to 225,000 barrels of oil per day in 2003. Increasing our production capacity is the best and fastest way for us to achieve lower costs and higher margins. The economics of Millennium are strong enough to generate a return higher than the cost of capital, even if oil prices fall back below US\$15 per barrel.

In early 2000 we entered the next phase of oil sands growth beyond Project Millennium by announcing our plan to invest \$750 million to further expand Suncor's oil sands business. The plan includes building a commercial scale in-situ facility and expanding the upgrading capacity of our Fort McMurray operation. Our Firebag In-Situ Oil Sands Project is designed to deliver an additional 35,000 barrels per day of bitumen to our Oil Sands plant by the end of 2004. The Firebag heavy oil deposits, located about 40 km from Fort McMurray, could have a recovery potential of about five billion barrels of bitumen and will be developed using steam-assisted gravity drainage technology that we piloted at our Burnt Lake facility.

Our long-term plans call for further investments to increase in-situ production in stages to about 140,000 barrels of bitumen per day by the end of the decade. With increasing investment in new technology and continuing actions to reduce

the environmental impacts of our operations, our long-term vision is to increase our oil sands production to about 400,000 to 450,000 barrels per day in 2008.

Suncor's Management Team Changes to Support Growth

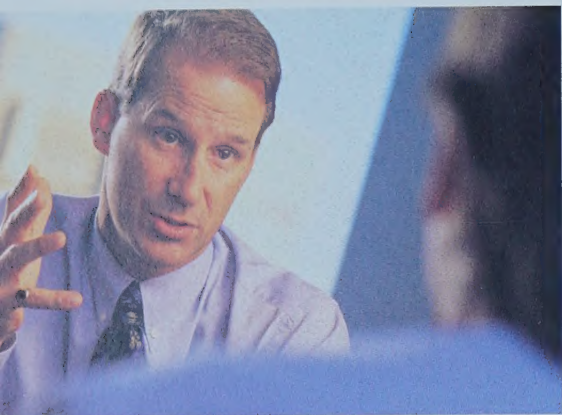
As the energy industry enters a new era marked by consolidation and technological innovation, I am confident that Suncor is well positioned to compete in this new environment. Changes to our management team, which came into effect at the start of 2000, strengthen us further to meet the many challenges we face in the years ahead.

I should note that, with our Project Millennium expansion in full swing, we have not changed the leadership of our Oil Sands business unit. Mike Ashar remains in his role as Executive Vice President of Oil Sands, and is fully engaged in stewarding growth and maintaining our base operations in Fort McMurray.

To reflect our increasing emphasis on heavy oil development and oil shale, Barry Stewart, formerly Group Executive Vice President, Exploration and Production, now becomes Executive Vice President, In-situ and International Oil. Barry's responsibilities will include working with Peter Hopkins, Managing Director of Suncor Energy Australia, along with leadership of our mineable oil and heavy oil teams. Barry will focus on developing solid commercial opportunities to capitalize on the heavy oil and oil shale technologies that could provide Suncor with unique strategic advantages on a global basis.

Dave Byler, formerly Chief Financial Officer, is now Executive Vice President, Exploration and Production. Dave will focus primarily on improving financial performance and building Suncor's natural gas business in Western Canada.

Tom Ryley, formerly Vice President, Planning and Corporate Development, is now Executive Vice President of Sunoco in Toronto. He will also head up the downstream integration team based in Calgary.



Mike O'Brien, formerly Executive Vice President, Sunoco, becomes Executive Vice President, Corporate Development and Chief Financial Officer in Calgary. In addition to providing financial and strategic planning leadership, Mike will also focus on corporate sustainability and broadening Suncor's business portfolio with commercially viable alternate energy opportunities.

Four Priorities for the Future

At Suncor we continue to focus ourselves on the two things that we believe will maintain and build value for our stakeholders: getting the most from our existing businesses, and implementing our growth plans. And our growth plans become more sharply focused with each passing year. This year's annual report has a new section that highlights Suncor's priorities for future growth. Here's my executive summary of these priorities:

- 1. Expand Oil Sands:** After the Steepbank Mine project, Project Millennium is the next major step in this direction, and more growth is in store for our oil sands operation in the future. Suncor's extensive land position in northeastern Alberta has mineable and in-situ resources that have the potential to provide a major platform for future growth well into this century. By increasing production and driving costs down, we are moving closer to our goal of becoming the lowest cost producer of oil in North America. As we expand our oil sands operation and tie in the nearby Firebag in-situ development, we will be working on new technologies to lower our costs and reduce our impact on the environment.
- 2. Transfer Our Expertise Internationally:** As the world's first oil sands developer, Suncor is uniquely positioned to create value from the billions of barrels of oil sands and oil shale deposits worldwide. Responsible development of these resources began with our Stuart Oil Shale Project in Australia and could continue in other countries.

"We're starting to see the next horizon of growth for Suncor as we plan further expansion of our oil sands business and begin to push into new geographical and technological frontiers."

TERRY HOPWOOD

Vice President, General Counsel and Secretary

- 3. Further Integrate Our Business:** Suncor's production is targeted to increase to 225,000 barrels per day in 2003, with a target of further expansion to 400-450,000 barrels per day in 2008. Our goal is to capture the greatest value from our increasing production. This means maximizing the operating synergies between Oil Sands and our Sarnia refinery, and exploiting the marketing potential we have as an integrated energy company. It also could include expanding our presence in the North American refining business through long-term marketing arrangements, acquisitions, alliances, partnerships and joint ventures.

- 4. Focus on Natural Gas and Alternative and Renewable Energy:** We are continuing our efforts to grow our natural gas business, and have initiated a comprehensive strategic review to determine ways to improve financial and operational performance and define new and profitable opportunities for growth.

We have also made a commitment to invest \$100 million over the next five years in alternative and renewable energy sources such as deriving ethanol fuel from biomass and producing methane from municipal solid waste. Pursuing new forms of energy has the potential to reduce our impact on the environment and create long-term value for our shareholders.

Toward a Sustainable Energy Company

In this new era of giant global oil companies, Suncor must look for new, sustainable ways to compete. This means we must concentrate on developing niches in the marketplace where we can demonstrate a strategic competitive advantage and where we can concentrate on becoming a leader. Our oil sands business is the best example of this philosophy in action. The strength of our oil sands business also gives us the freedom to invest in other areas with longer-term growth potential such as alternative and renewable energy.

One of Suncor's biggest challenges is to find a way forward that reconciles our desire to increase shareholder value and develop

"Suncor has great people and a solid vision. As we grow our business, building on our reputation as a caring company and a great place to work is integral to our future success."

SUE LEE

Senior Vice President, Human Resources and Communications



the products our customers want, with the need to reduce our environmental impact and contribute to the well being of our society. For us, that is what sustainable development is all about.

In 1999 we published our third bi-annual We Care report, which documents our progress on environment, health and safety, and social responsibility. The report was mailed to a wide range of stakeholders, including all Suncor shareholders. It provides a comprehensive look at how we have improved our performance over the past two years – and areas where we still need more attention. The report helps to clarify Suncor's vision of long-term sustainability and shows how we are adopting this vision as the basic foundation of our business planning.

For me, the highlights from the report include executing the first part of our emission reduction trade with Niagara Mohawk Power Corporation, starting to use life-cycle value assessments to help evaluate the impacts of our projects and business activities, and the evolution of the Suncor Energy Foundation as our vehicle for investing to improve the well-being of our communities. If you haven't seen it, I invite you to take a look at the whole report, which is available on Suncor's website at www.suncor.com or by phoning 1-800-558-9071.

We certainly don't have all the answers, but it's gratifying to get independent recognition of our efforts. Last year, in recognition of Suncor's commitment to environmental and social responsibility, the Dow Jones Sustainability Group Index named Suncor as the world-wide leader in the oil and gas industry. This is a new global index of 200 companies in 22 countries that are committed to the principles of sustainable development. The index represents a market capitalization of US\$4.3 trillion and is a symbol of the growing interest by the world investment community in sustainable development. Suncor's inclusion on the list as an industry leader is one sign that we are making progress on our sustainability goals.

Good Leadership Depends on Great People

A great workplace takes great people, and it's a tribute to the leadership and employees at Suncor that in 1999 our company

was named as one of Canada's 35 Best Companies to Work For in the Globe and Mail Report on Business magazine.

In 1999 I also had the great honour of being named Canada's Outstanding CEO of the Year. I accepted the award on behalf of all Suncor employees, because I believe effective leadership depends on the quality and commitment of the people who work with you. With this in mind, I'd like to thank all my colleagues at Suncor for another year of dedication, innovation and hard work.

As in years gone by, Suncor's Board of Directors has been a source of invaluable advice and guidance. They represent a source of experience, knowledge and wisdom for which I am always grateful.

I think it's fair to say that over the last several years Suncor has built a positive reputation for itself among investors, customers and in the communities in which we operate. With each passing year we have seen an increasing understanding of our past performance as well as our future potential. The past year was a pivotal one for Suncor. In many ways we have set ourselves apart from the pack, achieving a leadership position in the development of Canada's oil sands and strengthening our commitment to becoming a sustainable energy company.

Our vision of Suncor's long-term future has never been clearer, and I believe it has never been more achievable than it is right now. I am confident that everyone at Suncor is equally committed to making that future happen.

Rick George
President and Chief Executive Officer



PRIORITY

- **Project Millennium expansion**
- **Firebag in-situ development and upgrader expansion**
- **Further long-term Oil Sands expansion**

Strategic Role: Economies of scale favour oil sands expansion. The \$2-billion second phase of Project Millennium is designed to increase oil sands production to 225,000 barrels per day in 2003. When combined with a \$750-million in-situ project and further expansion of Suncor's oil upgrading facilities, a new phase of growth comes into view.

Production of 260,000 barrels per day is targeted for 2004, with a long-term goal of 400,000 to 450,000 barrels per day in 2008. Increased production and improved efficiency translate into lower unit costs, giving Suncor the potential to become North America's lowest cost producer of crude oil.

Expand Oil Sands

"The coke drums are a key piece of Project Millennium – and just getting them from Edmonton to our plant site is an incredible engineering, communications and logistical challenge."

Bert Lang, Vice President, Project Millennium

Land of Giants. Four giant coke drums are at the heart of the expanding Oil Sands upgrading process. Inside these 438-ton units, heated bitumen is thermally cracked to produce lighter, more usable hydrocarbons and residual coke. The units require two specialized trailers with five tandem axles each and a total of 320 wheels to transport them from Edmonton to the plant site over 10 days. The cokers are so massive they must be shipped in mid-winter so the frozen road can bear their weight.

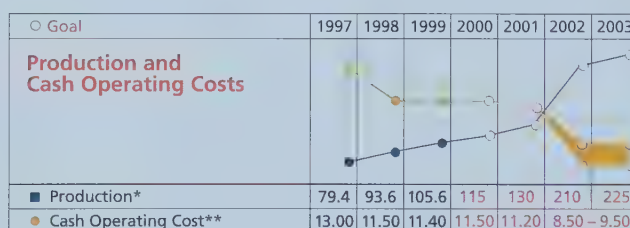
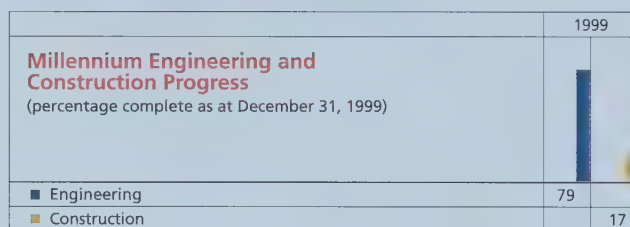


Project Millennium Highlights:

- The \$2-billion second phase of the project is scheduled to begin commissioning in the second half of 2001, and is designed to increase total Oil Sands production to 225,000 barrels per day in 2003.
- \$1.3 billion was committed to the project by the end of 1999.
- Nearly 80% of the engineering and 17% of construction was completed by 1999 year-end.
- The construction workforce is expected to peak at 3,000 in 2001. When completed, Project Millennium will add about 600 new jobs to the local economy.
- In 1999 Project Millennium had no lost-time accidents with a total of 1.9 million person-hours worked.

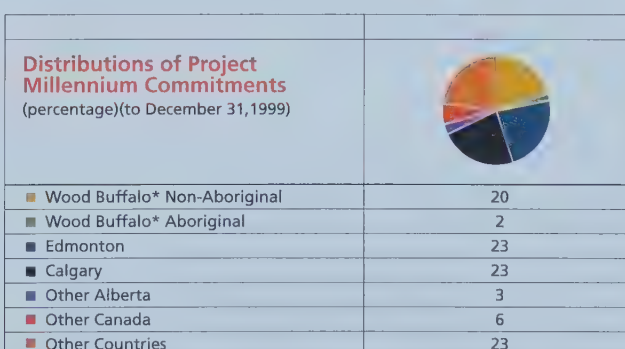
Economies of Scale Drive Oil Sands Growth

In the business of mining for oil, bigger is better. Project Millennium is part of staged growth initiatives that are designed to nearly double the size of Suncor's current Oil Sands operation. The benefits of higher production and lower costs are demonstrated by the project's bottom-line economics: even if the price of crude declines below US\$15 per barrel, the project would still generate a return higher than Suncor's 11% cost of capital.



* Thousands of barrels per day

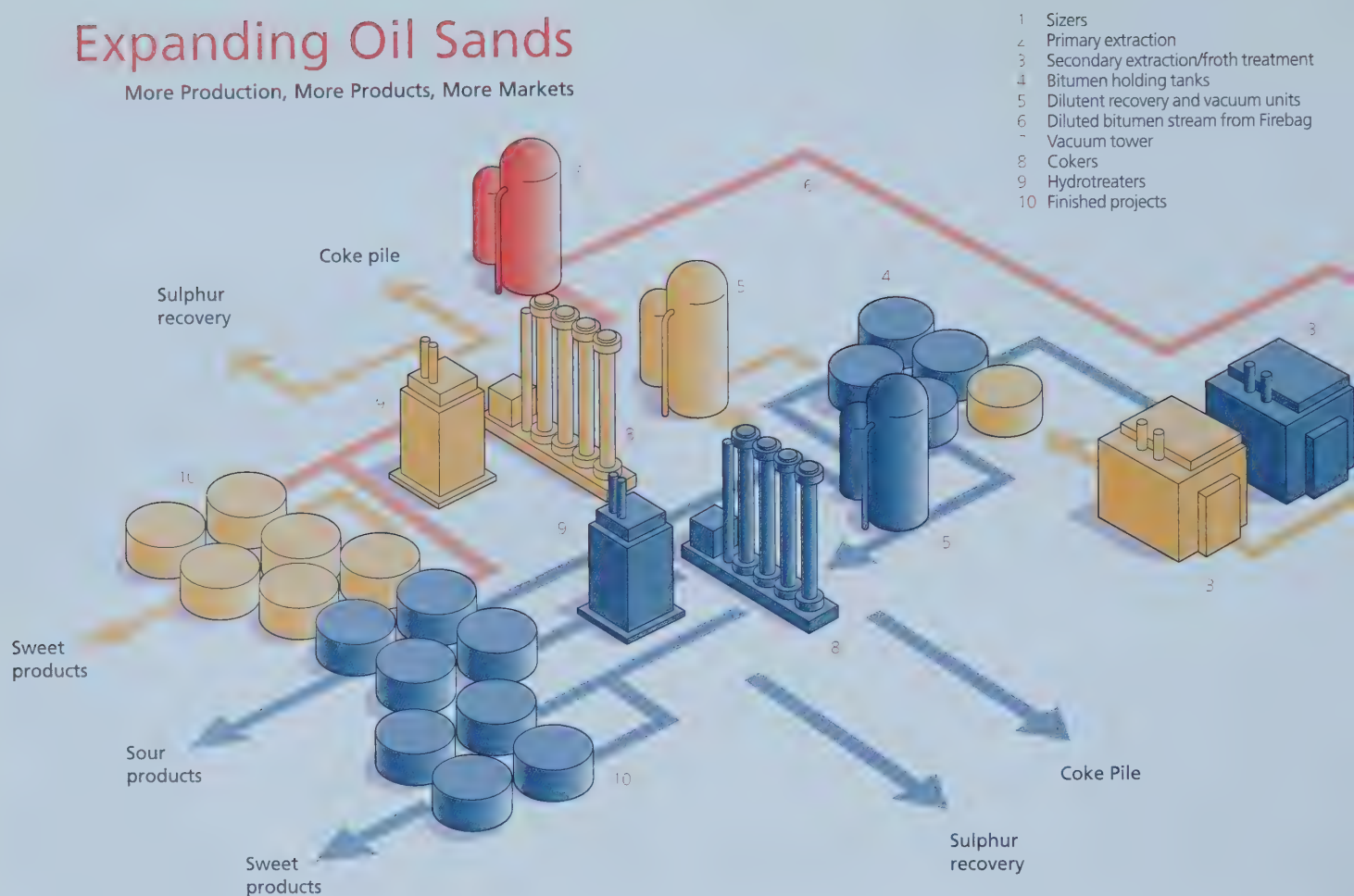
** Dollars per barrel



* Fort McMurray and area.

Expanding Oil Sands

More Production, More Products, More Markets



Twinning the Oil Sands Process – Two is better than one

Project Millennium will increase reliability and availability of facilities. Each part of the process, from mining to upgrading, will be “twinning.” This means the ability to sustain some of the cash flow from operations during planned maintenance shutdowns of one process or train.

Manufacturing Energy

Suncor is more than an oil company. It is a “manufacturer” of petroleum products, providing its customers with a range of products, from diesel fuel to light sweet and light sour crudes – plus byproducts like petroleum coke and sulphur. And, with access to decades of reserves, Suncor’s customers can enjoy the benefits of a long-term, reliable production source. As Suncor increases its oil sands production, the company is seeking markets and long-term customers. The goal: to become a major niche marketer of custom petroleum products, serving the diverse needs of North America’s energy marketplace.

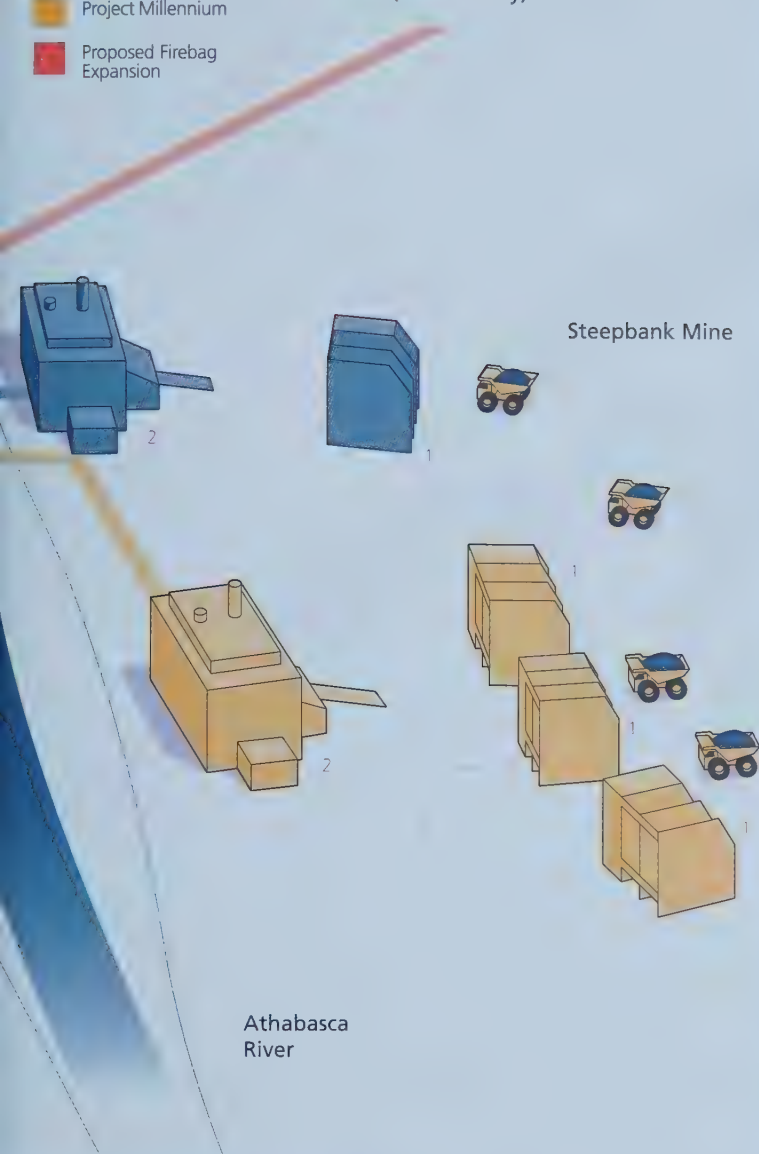
Forging Alliances

Project Millennium is managed by a group of leading companies that formed an Alliance to undertake engineering, procurement, construction, commissioning and start-up of the oil sands expansion. In addition to Suncor, the Alliance includes three engineering companies - Bantrel Inc., Fluor Daniel Canada Inc., SNC-Lavalin Engineers & Constructors and Millennium Construction Contractors (a joint venture construction organization comprised of Bechtel Canada Co. and Fluor Constructors Canada Ltd.). Members of the Alliance signed an incentive-based agreement to ensure joint accountability for the project. The agreement includes a risk/reward formula based on total installed cost, schedule, production reliability, construction safety and local content.

The same philosophy of working with third parties toward mutual goals governs other aspects of oil sands growth: In 1999 TransAlta Energy Corporation agreed to operate Suncor’s existing energy plant as well as build, own and operate a \$315-million cogeneration facility at Fort McMurray that will meet a portion of Suncor’s future energy requirements for Project Millennium.

- Existing facilities
- Project Millennium
- Proposed Firebag Expansion

Firebag In-situ Project
(40 km away)



Athabasca
River

Beyond Millennium – Suncor's Firebag In-Situ Oil Sands Project

Project Millennium represents the beginning of a new era of oil sands growth for Suncor. The next step is a \$750-million in-situ development and further expansion of the company's Fort McMurray upgrading facility. About 40 kilometres from the current mine site are Suncor's Firebag properties, with in-situ recovery potential of five billion barrels of heavy oil, called bitumen. In-situ is Latin for "in place," meaning the oil is too deep to be mined from the surface. For the past three years, Suncor has been testing and refining steam-assisted gravity drainage technology (SAGD) at its Burnt Lake pilot project, near Cold Lake in Northern Alberta. Suncor plans to transport heavy oil from Firebag to Suncor's oil sands facility for processing into oil products or to be sold directly into North American heavy oil markets. This new expansion of Suncor's oil sands business is subject to Suncor Board of Directors and regulatory approval.

A sustainable approach

The Issue: The oil sands production process creates greenhouse gas (carbon dioxide – CO₂) emissions (GHG). Suncor's oil sands expansion is designed from the ground up to be energy efficient. In 2002, at the completion of Project Millennium, there will be an estimated 42% reduction of GHG per unit of production from the 1990 levels. There will, however, be an absolute increase in greenhouse gas emissions due to production increases.

The Challenge: How to increase production volume while at the same time containing the company's net greenhouse gas emissions to 1990 levels.

Suncor's Response: Suncor has in place a comprehensive Greenhouse Gas Management Plan that affects the entire company. The goal is no net increase in emissions: in other words, for every new tonne of CO₂ released into the atmosphere, one tonne will be removed. Initiatives to meet this goal include:

- **Managing Suncor's own emissions.** All of Suncor's growth projects are designed with energy efficiency in mind. Reducing greenhouse gases can often also reduce operating costs.
- **Pursuing greenhouse gas offsets.** These are domestic or international actions taken outside Suncor's own operations that are designed to reduce or absorb GHG emissions anywhere in the world, and which, if recognized by the appropriate authorities, could help Suncor achieve its goal. These actions include investments in alternative and renewable energy, forest conservation and reforestation programs, and emissions reduction trading.
- **Supporting research and education.** Climate change is a global issue that requires a global solution. This means supporting climate change research and funding education programs that promote awareness and encourage positive action from all Canadians.



Transfer expertise

and technology from Oil Sands to new businesses

- **Stuart Oil Shale Project demonstration plant**
- **Potential future phases of Stuart development**
- **Other international mineable oil opportunities**

Strategic Role: A key priority for the future will be transferring the company's knowledge, technology and expertise to develop other mineable oil sands and oil shale deposits internationally. The Stuart Oil Shale Project in Australia is Suncor's first step in this long-term strategic direction.

Commitment to Environmentally Responsible Action

As Suncor ventures beyond Canada, its environmental responsibilities take on a global significance. This is especially true in its approach to managing greenhouse gas emissions.

At Stuart, the company's objective is to produce oil with net greenhouse emissions equal to or less than

conventional oil recovery. If the project were to be scaled up to 85,000 barrels per day, Stuart would represent less than 1% of Australia's total current CO₂ emissions.

In terms of its overall impact on the environment, the Stuart Project's waste byproducts are non-hazardous

and do not require tailings ponds. The end product is high quality light crude oil that is low in sulphur and an ideal feedstock for producing the next generation of cleaner transportation fuels.

"The design, construction and commissioning of the Stuart Oil Shale Project is giving us invaluable experience that we can apply to future oil shale development. Being a pioneer has daunting challenges, but can also have enormous potential rewards."

Peter Hopkins, Managing Director, Suncor Energy Australia Pty. Ltd.



The Global Oil Mining Potential – Transferring Suncor's Expertise outside of Canada

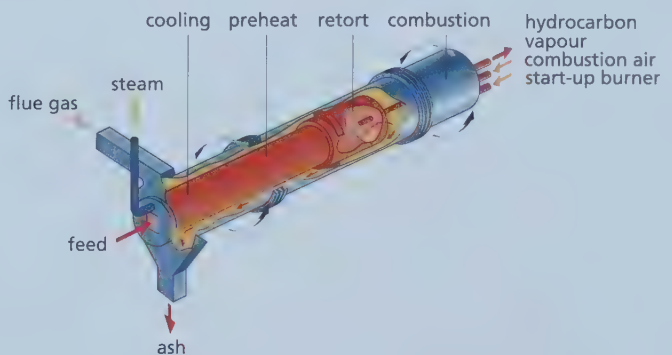
Suncor has created a Mineable Oil Team to investigate business opportunities related to the development of oil sands and oil shale deposits outside of Canada. The current focus is on oil shale deposits that can be exploited using the Alberta Taciuk Process (ATP) technology. Becoming a global leader in oil shale development is a potential future business niche for Suncor. It represents a distinct area of new energy development where the company can realize the value of these potential resources.

For Suncor, transferring mineable oil expertise abroad is a clear priority for future growth and provides a unique investment opportunity. Here are some of the benefits:

- Energy produced from oil shale can be converted into various useable forms – petroleum products, petrochemicals, crude oil, and electricity – depending on the needs of local infrastructure or market demand.
- The dry ATP process has no tailings ponds.
- Development of mineable oil deposits could be attractive to host countries as an economic and infrastructure investment opportunity.

Stuart: Suncor's first step abroad

The C\$237 million Stage 1 pilot plant was mechanically completed during 1999. Commissioning the plant is taking longer than expected, and was not completed by year-end. Suncor and its Australian co-owners, SPP/CPM, expect that commissioning will be complete in 2000. A decision about the technical and operational viability of the technology will be made later in the year. Stuart has been an invaluable first step for Suncor, providing data on the scaling up of the Taciuk technology and experience in entering international markets.



The Heart of the Stuart Project. Extraction of oil from shale at Suncor's Stuart Project hinges on the success of the Alberta Taciuk Processor (ATP). The ATP is a large rotating kiln. Crushed oil shale is fed into the ATP unit, which heats the ore to 500°C. The hydrocarbons locked in the shale are turned to vapour, which can then be captured and condensed into oil. Currently the Stage 1 plant is being commissioned and is targeted to produce 4,500 barrels of light crude oil per day.

Integrate

downstream and upstream businesses

- Expand presence in North American refining business with long-term marketing arrangements, alliances, acquisitions, partnerships and joint ventures

Strategic Role: For Suncor, integration means making strategic connections, both within our business and with our customers. Integration is a way of optimizing value for Suncor's energy production all the way from putting the shovel in the ground at the company's oil sands business, to serving its customers at the gas pumps. Further integration will enable Suncor to respond to new markets and new customers with value-added products.

Sunoco's Sarnia Refinery. Located on the shores of the St. Clair River in Sarnia, Ontario, Sunoco's refinery has the flexibility to produce a high proportion of transportation fuels and petrochemicals. It is currently running at 95% capacity. In 1999 the refinery continued to strive to attain a Best in Class ranking, and became the first refinery in Canada to receive ISO 14000 accreditation, recognizing its effective environmental management systems. The Sunoco refinery provides a secure market for Suncor's oil sands feedstock and is a model for potential future expansion into other North American refining markets.



"Suncor is exploring a wide range of opportunities where we can leverage our position as an oil producer to serve a broad range of customers in Canada and the U.S."

Richard Brown, General Manager, Suncor Energy Marketing Inc.

Capturing Value from Mine to Refinery

Suncor's oil sands production growth represents a marketing opportunity that can be met by further integration of Suncor's upstream and downstream businesses. Suncor currently sells crude oil production to its Sunoco refinery and has long-term supply agreements with industrial customers such as Koch Oil. By securing access to new customers and refineries in the U.S., Suncor has the potential to increase the value it receives from its growing production base.



With pipeline connections reaching into the heart of the North American oil market, Suncor is well positioned to find secure homes for its growing oil sands production.

Marketing Suncor's Energy

Suncor's marketing efforts are focused on maximizing the market value for current and future production and capturing the integration value across all of the company's businesses. Suncor intends to:

- Create and establish markets for Suncor's crude oil production growth as well as byproduct sales.
- Promote the utilization of Suncor's custom blending capability and establish long-term sales agreements with individual refiners for both sour and sweet feedstocks.
- Manage infrastructure so product delivery to customers is enhanced and Suncor is positioned as a low-cost supplier to the market.
- Continue to pursue future opportunities to develop a dominant position in Athabasca bitumen supply and marketing.
- Seek opportunities to potentially expand the company's refining activities by evaluating several approaches to downstream integration, including possible acquisitions, joint ventures or long-term agreements with other refiners.



Focus

on natural gas and alternative and renewable energy

- Natural gas exploration and production
- Alternative and renewable energy
- Coal bed methane

Strategic Role: Suncor has the potential to be a major player in the growing Canadian natural gas industry, and will continue its exploration and production activities in the Western Canada Sedimentary Basin. The company also sees long-term potential in alternative and renewable energy, and is actively pursuing opportunities in areas such as extracting ethanol from biomass, producing methane from municipal solid waste, developing coal bed methane, and producing energy from the wind and the sun.

"We see long-term potential for growth in the North American natural gas business. We will seek ways to profitably exploit our western Canadian natural gas properties and examine opportunities to develop coal bed methane deposits in Australia and other countries."

Dave Byler, Executive Vice President, E&P

Focus on Natural Gas

Suncor's E&P business has been increasing its natural gas focus for the past seven years, based on management's belief that commodity prices will strengthen and market access will improve. E&P will focus its exploration and production program on developing natural gas from the Western Canada Sedimentary Basin.

Alternative and Renewable Energy

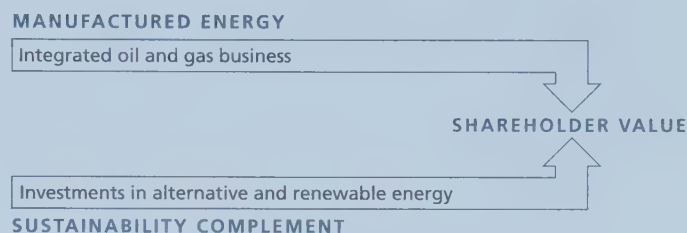
In early 2000, Suncor announced plans to invest \$100 million over the next five years in alternative and renewable energy, including research and development projects and commercial ventures. Gerry Manwell, the Suncor executive who spearheaded Suncor's oil sands growth plans, is now leading Suncor's efforts to identify emerging technologies that can be economically sustainable, yield verifiable environmental benefits and provide a close fit with Suncor's existing technical expertise and operating experience.

Sunoco's Ethanol-Enhanced Gasolines

Since 1998 Sunoco, Suncor's refining and marketing arm in Ontario, has been offering its customers ethanol-enhanced gasoline at all its retail stations. By putting Sunoco gasoline in their tanks, Ontario consumers reduce emissions and improve air quality equivalent to taking 20,000 cars off the road.

Suncor's Journey Towards Sustainability. Suncor is following parallel paths to achieve value creation and its goal of sustainable development. One path leads to the responsible development of hydrocarbon resources, such as oil sands and natural gas, to meet the current and future needs of Suncor's customers and shareholders. The second path involves acting now to develop alternative and renewable sources of energy that contribute to protection of the environment and the long-term sustainability of Suncor.

Parallel Paths to value creation



"Suncor is actively seeking opportunities to invest in alternate and renewable energy, with a long-term view of creating a new and viable business for the company while at the same time reducing our impact on the environment."

Gerry Manwell, Vice President, Alternate Energy Business Development

Coal Bed Methane Exploration in North America and Australia – An alternative source of natural gas and potential carbon sink

Natural gas (methane) is sometimes trapped in underground coal deposits. Once just a byproduct of coal mining, coal bed methane is now a valuable resource that can be recovered, gathered and transported in ways similar to natural gas from conventional sources.

In 1999 Suncor acquired coal bed methane (CBM) exploration rights to over a million acres of land in northeastern Australia. This represents the beginning of Suncor's exploration for CBM deposits, which have the potential to become an important future source of natural gas in both North America and Australia.

Coal beds may also be valuable as a potential way to trap carbon dioxide, giving Suncor another way to reduce greenhouse gas concentrations in the atmosphere. Suncor is participating in an experimental program in Alberta to see if underground coal deposits can be used as a permanent carbon sink and enhance gas recovery.

Management's Discussion and Analysis

Overview***

Suncor Energy Inc.'s corporate centre is located in Calgary, Alberta. The company is currently comprised of three operating businesses: an oil sands operation (Oil Sands); a conventional oil and gas business (Exploration and Production – E&P); and a refining and marketing operation (Sunoco).

In 2000, Suncor established an In-situ and International Oil development unit, which includes the Stuart Oil Shale Development Project in Australia and the company's recently announced Firebag in-situ project 40 kilometres from Fort McMurray.

1999 – Earnings Increased 6%

Earnings in 1999 increased 6% to \$200 million (\$1.61 per common share), from \$188 million (\$1.70 per common share) in 1998. Cash flow from operations was \$591 million (\$5.02 per common share), representing the seventh consecutive year of cash flow growth. Cash flow from operations in 1998 was \$580 million (\$5.27 per common share). Revenue in 1999 was \$2.4 billion compared with \$2.1 billion in 1998. Per share

amounts for earnings and cash flow from operations in 1999 reflect payments on the **preferred securities** issued in 1999.

The increase in consolidated earnings was primarily the result of higher crude oil prices in the last three quarters of 1999, higher natural gas prices, record Oil Sands sales volumes, gains on asset sales and improved retail margins. The impact of these positive factors was partially offset by crude oil and natural gas **hedging** losses (\$56 million in 1999 compared to gains of \$47 million in 1998), increased costs, lower conventional oil and gas production, lower refining earnings due to higher crude oil and feedstock costs and higher taxes. Cash flow from operations increased only slightly, despite the earnings increase, because the cash associated with gains on disposal of assets (\$92 million in 1999; \$11 million in 1998) is not included in cash flow from operations. The cash associated with gains on divested assets is reported as a reduction in cash used in investing activities. 1998 cash flow from operations of \$580 million included \$34 million in income tax refunds. There was no such benefit in 1999.

Consolidated Financial Results

(\$ millions)	1999	1998	1997
Earnings	200	188	223
Cash flow provided from operations	591	580	575
Investing activities	1 290	937	884
Dividends – common shares	75	75	74
– preferred securities	37	0	0
Long-term borrowings	1 306	1 298	767

Relative Segment Contribution

(before the impact of corporate and elimination adjustments, expressed as %)	1999	1998	1997
Earnings			
Oil Sands	70	70	74
Exploration and Production	17	11	10
Sunoco	13	19	16
Cash flow provided from operations			
Oil Sands	60	53	54
Exploration and Production	25	28	26
Sunoco	15	19	20
Capital Employed			
Oil Sands	55	53	48
Exploration and Production	29	28	29
Sunoco	16	19	23

Industry Indicators

(average for the year unless otherwise noted)	1999	1998	1997
West Texas Intermediate (WTI) crude oil U.S.\$/barrel at Cushing	19.30	14.40	20.60
Canadian 0.3% par crude C\$/barrel at Edmonton	27.50	20.45	27.80
Light/sour crude oil price differential C\$/barrel at Edmonton	2.80	3.20	3.45
Natural gas U.S.\$/thousand cubic feet at Henry Hub	2.27	2.14	2.55
Natural gas (Alberta spot) C\$/thousand cubic feet at Empress	3.00	2.25	1.95
Natural gas exports to the U.S. trillions of cubic feet	3.2*	3.1	2.9
New York Harbour 3-2-1 crack U.S.\$ barrel**	2.47	2.85	4.09
Refined product demand (Ontario/Quebec) percentage change over prior year	1.5*	4.2	2.0
Exchange rate: C\$: U.S.\$	0.67	0.67	0.72
Exchange rate: C\$: Australian\$	1.04	1.07	0.97

* Estimate

** New York Harbour 3-2-1 crack is an industry indicator measuring the margin on a barrel of oil for gasoline and distillate. It is calculated by taking 2 times the New York Harbour gasoline margin plus 1 times the New York Harbour distillate margin and dividing by 3.

***The tables and charts in this document form an integral part of Management's Discussion and Analysis and should be referred to when reading the narrative. References to Suncor or the company include Suncor Energy Inc. and its subsidiaries and investment in joint ventures, unless otherwise stated. Management's Discussion and Analysis contains certain forward-looking statements which are based on Suncor's current expectations, estimates, projections and assumptions and were made by the company in light of its experience and its perception of historical trends. All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected expenditures, commodity prices, costs, schedules and production volumes, operating or financial results, are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects," "anticipates," "plans," "intends," "believes," "projects," "indicates," "could" and similar expressions. These statements are not guarantees of future performance and involve a number of risks, uncertainties and assumptions. Suncor's business is subject to risks and uncertainties, some of which are similar to other oil and gas companies and some of which are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements as a result of known and unknown risks, uncertainties and other factors. The risks, uncertainties and other factors that could influence actual results include: changes in the

general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; fluctuations in commodity prices; fluctuations in exchange rates; Suncor's ability to respond to changing markets; the ability of Suncor to receive timely regulatory approvals; the successful implementation of its growth projects, including Project Millennium; the integrity and reliability of Suncor's capital assets; the cumulative impact of the resource development projects; Suncor's ability to comply with current and future environmental laws; the accuracy of Suncor's production estimates and production levels and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venturers; competitive actions of other companies, including increased competition from other oil and gas companies or from companies which provide alternative sources of energy; the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; actions by governmental authorities including increasing taxes, changes in environmental and other regulations; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to Suncor; and the occurrence of unexpected events such as fires, blowouts, freeze ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor.

Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company's annual information form on file with the Alberta Securities Commission and certain other securities regulatory authorities. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

Oil Sands

Bitumen

Tar-like form of oil that cannot be produced by conventional means. When extracted from oil sands, it can be upgraded into light sweet crude and other products.

Maintenance Shutdown

Long-term preventative maintenance activities that involve shutting down major parts of, or an entire facility.



Overview

Suncor has more than 30 years' experience in mining and upgrading oil sands to produce crude oil on a commercial basis – more than any other company in the world.

Suncor uses the following proven technology and processes to produce oil from its leases in the Athabasca oil sands, near Fort McMurray, Alberta:

- Giant trucks and shovels mine the oil sands.
 - The **bitumen** is separated from the sand in the extraction process, then upgraded to high quality "light sweet" and "light sour" crude oil products and diesel fuel.
 - The crude oil products are blended to customer specifications and sent by pipeline to markets in Canada and the U.S.
- The Oil Sands business also has an on-site energy plant operated by TransAlta Energy Corporation (TransAlta) that generates steam and electricity using petroleum coke – a byproduct of the upgrading process – and natural gas.

Suncor's top growth priority is to expand its Oil Sands business. In 1999, Suncor received government approval for Phase 2 of the \$2.2-billion Project Millennium, which entails a staged expansion of production to an estimated 225,000 barrels per day in 2003, up from production of 105,600 barrels per day in 1999. By the end of 1999, construction on the project was 17% complete and detailed engineering was 79% complete.

In early 2000 Suncor announced plans to invest \$750 million to further expand its oil sands business by adding a commercial scale in-situ project and bolstering the upgrading capacity of its Fort McMurray operation. This plan is subject to Board of Directors and regulatory approvals.

Results of Operations and Investing Activities 1999 vs 1998

Oil Sands – Summary of Results

(\$ millions unless otherwise noted)	1999	1998	1997
Revenue	889	768	751
Production			
(thousands of barrels per day)	105.6	93.6	79.4
Average sales price			
(including the impact of hedging)			
(\$ per barrel)	23.84	22.18	26.36
Earnings	174	150	179
Cash flow provided			
from operations	405	320	331
Total assets	3 178	2 081	1 689
Investing activities	1 085	514	531

Earnings Analysis

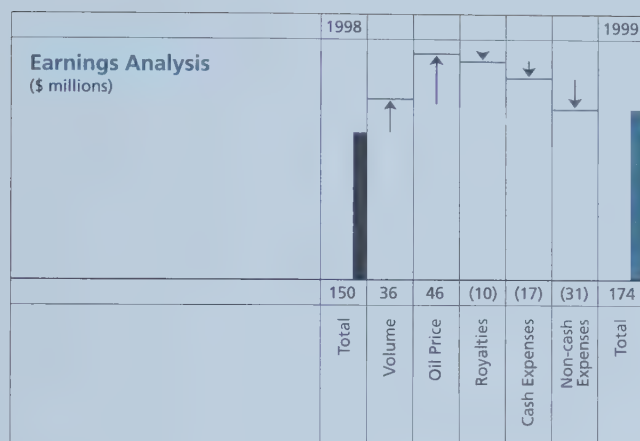
Increased Sales and Selling Price Contribute to a 16% Increase in Earnings

Oil Sands earned \$174 million in 1999 compared with \$150 million in 1998. This increase was mainly attributable to a 7.5% increase in sales volumes and a 7.5% increase in Oil Sands crude oil price. These factors were partly offset by higher operating costs.

Benchmark crude prices increased 34% over 1998. This increase was tempered by a loss on Suncor's hedging program which decreased year-over-year Oil Sands earnings by \$88 million as well as an increase in pipeline costs for Oil Sands that impacted year-over-year earnings by \$15 million. The higher pipeline costs relate to the Athabasca Pipeline, which was commissioned in April 1999 and on which Oil Sands ships sour crude oil.

During a 28-day, \$20-million planned **maintenance shutdown** in 1999, Oil Sands halted production of sweet (low-sulphur) crude oil and produced only lower-priced sour crude oil. In addition, the selling price of sour crude declined during this period as a result of short-term market conditions.

The combined impact of the above price factors resulted in a year-over-year increase in earnings of \$46 million.



Record sales volumes and higher oil prices, partly offset by higher expenses, resulted in a 16% earnings improvement.

Oil Sands Production Increases 13%

Oil Sands increased production in 1999 for the seventh consecutive year to an average of 105,600 barrels per day from 93,600 barrels per day in 1998. This increase was attributable to Suncor's new Steepbank Mine and fixed plant expansion (a vacuum tower and diluent recovery unit), which had its first full year of production in 1999.

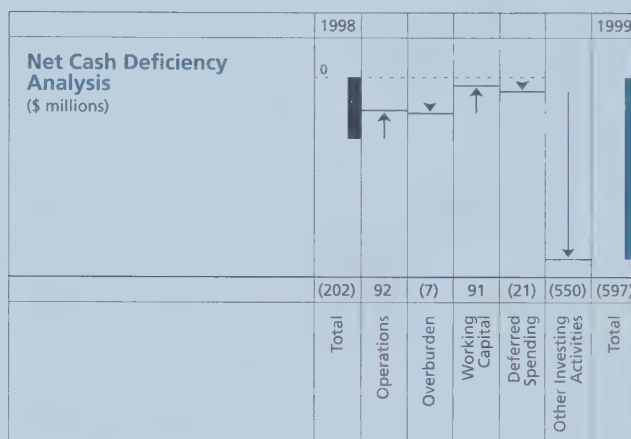
Two unplanned outages at Oil Sands in 1999 lasted a total of 16 days and resulted in approximately 1.8 million barrels of lost production. These outages were precipitated by a change in feedstock resulting from the operation of the new fixed plant expansion. Parts of the unit that failed were redesigned during the second outage in September, with the objective of improving reliability.

Due to a build in inventory, primarily associated with filling the Athabasca Pipeline, only 102,200 barrels per day were sold in 1999. Sales volumes in 1998 were 95,100 barrels per day. This volume increase resulted in a year-over-year improvement in earnings of \$36 million.

Royalties

Crown royalties payable by Suncor to the Government of Alberta increased 39% in 1999, to \$48 million, as a result of higher sales volumes and prices. The higher Crown royalties were partly offset by a \$5-million (pre-tax) decrease in royalties paid to Union Pacific Resources Inc. ("Union"), a reduction that occurred because Suncor mined fewer barrels in 1999 from the lease where Union has a royalty interest. The combined impact of the above factors was a net increase in total royalties expensed that reduced earnings by \$10 million.

Crown royalties in effect for Suncor's existing Oil Sands operations require payments to the Government of Alberta of 25% of revenues less allowable costs (including capital



Suncor's growth plans for its Oil Sands business is reflected in the \$550-million increase in investing expenditures that were only partially offset by the improved cash flow from operations and the working capital reduction. The reduction in working capital was due to the high level of project spending activity.

expenditures), subject to a minimum payment of 5% of gross revenues. In 1999 Suncor made royalty payments based upon a 5% minimum royalty.

Suncor's transition royalty agreement with the Alberta government took effect in 1999. The transition in 1999 of the company's Oil Sands operations to the new, generic oil sands royalty terms was initiated because more than 50% of Oil Sands production was derived from the Steepbank Mine. The agreement provides Suncor with additional allowable cost deductions to a maximum of \$158 million per year for 10 years (related to Suncor's original investment in the Oil Sands facility). Royalty rates beginning in 1999, the first year of the transition period, will be based on 25% of revenues less allowable costs with a minimum royalty of 5%. The 5% rate will change to a 1% rate beginning in the third year of the transition (2001). Suncor currently expects to remain at the 5% rate for the year 2000 and then be at the 1% rate until the middle of this decade. This assumption is based on expected future oil prices, production levels, operating costs and capital expenditures.

Expenses Increase by 16%

The increase in expenses in 1999 reduced Oil Sands' earnings by approximately \$48 million. Expenses were higher in 1999 as a result of increased costs in the following areas:

Non-cash charges (depreciation, depletion and amortization) increased, reducing 1999 earnings by \$31 million. The increase is due to: 1) changes to the mine plan that resulted in higher overburden amortization charges; 2) an increase in depreciation expense related to capital additions that increased production capacity, partly offset by an extension of the useful life of some fixed plant assets; and 3) an increase in amortization of turnaround expenditures as a result of the 1999 planned partial maintenance shutdown.

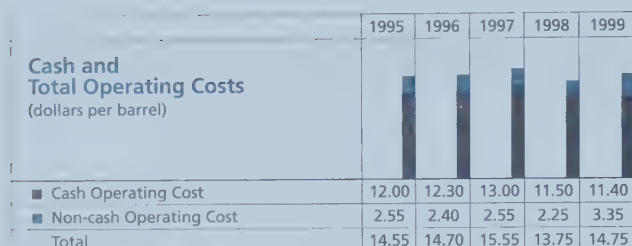
Overburden

Material overlying the oil sands that must be removed before mining. Consists of muskeg, glacial deposits and sand.

Working Capital

The excess of current assets (excluding cash) over current liabilities. The excess measures the ability of a business to finance current operations, for example, whether debt will need to be incurred to fund growth activities.

* This Section contains forward-looking information. Also refer to the Overview*** on page 21 of this report.



Non-cash costs increased from the 1998 level due to higher overburden costs and increased depreciation resulting from recent capital additions.

Cash expenses increased, resulting in a \$17-million reduction in earnings. The drivers of the increase were caused by: 1) higher production volumes; 2) mining and extraction operations being conducted on both sides of the Athabasca River (original mine expected to be shut down in the 2001 / 2002 time frame); and 3) increased natural gas prices.

Per-Barrel Operating Costs Increase

Cash operating costs did not change significantly from 1998. Per barrel costs were \$11.40 in 1999 – the first full year of operation for the Steepbank Mine and fixed plant expansion – compared with \$11.50 in 1998.

Total operating costs per barrel in 1999 were \$14.75 – against a target of \$13.85 – compared with \$13.75 per barrel in 1998. (Total operating costs are equal to the total expenses – including non-cash charges, but excluding royalties – divided by sales volumes). The increase in total operating costs is driven primarily by the increases in non-cash charges described above.

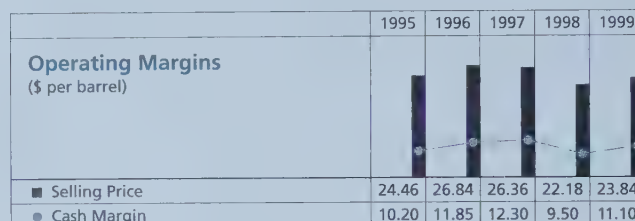
Cash Margin Increased 17% to \$11.10 per barrel in 1999

Oil Sands' cash operating margin was \$11.10 per barrel in 1999 compared with \$9.50 per barrel in 1998. The factors that influenced cash margins in the year were: 1) higher selling prices (before hedging) had a favourable impact of \$5.50 per barrel; 2) hedging gains and losses had an unfavourable net impact of \$3.85 per barrel; 3) cash operating costs had a favourable impact of \$0.10 per barrel; and 4) higher royalties had an unfavourable impact of approximately \$0.15 per barrel.

Net Cash Deficiency Analysis

Cash flow provided from operations was \$405 million in 1999 compared with \$320 million in 1998. The positive impact of improved cash margins and increased volumes (\$92 million) was partly offset by a \$7-million increase in **overburden** spending.

Oil Sands had an increase in funds from **working capital** of \$91 million relative to 1998. The increase was primarily due to a higher amount of accounts payable related to Project Millennium. This positive factor was partially offset by increases in accounts receivable and inventory levels.



The increase in the margin in 1999 primarily reflects a 7% increase in the crude oil selling price. The margin improvement of \$1.60 per barrel was tempered by payments associated with Suncor's hedging program that reduced the margin by \$2.05 per barrel.

Selling price – The average price from the sale of crude oil, including the impact of hedging activities.

Cash margin – The difference between the selling price received for products sold, and cash operating cost per barrel plus royalties per barrel.

Investing activities at Oil Sands increased from \$514 million in 1998 to \$1.1 billion in 1999. The increase was primarily due to spending of \$891 million on Project Millennium and planned maintenance shutdown spending increases of \$15 million. The increases were partly offset by a reduction in spending on the Steepbank Mine and fixed plant expansion.

Outlook***Phased Growth**

Project Millennium, currently estimated at a cost of \$2.2 billion, is designed to further increase Oil Sands' production capacity in two growth phases. The first phase of the project – the Production Enhancement Phase (PEP) – is expected to increase production to 130,000 barrels per day by 2001 at an estimated cost of \$190 million. The second phase is expected to increase production to 225,000 barrels a day in 2003.

Suncor's average production goal for 2002 is 210,000 barrels per day, down from the original target of 220,000 barrels per day. This change in the production target is due to planned maintenance shutdown work in 2002 that was previously scheduled for 2001. Project Millennium calls for an expanded mine, additional mining equipment, increased energy-services support, and twinning of the bitumen extraction and upgrading processes.

In 2000 Suncor announced a plan to further expand its oil sands facilities beyond 2003 with a proposed investment of \$750 million in an in-situ project and further expansion of the oil sands plant. The in-situ portion of the project would be integrated with Suncor's open pit mining operation, and, combined with plans to expand upgrading capacity, would enable output from Suncor's plant to reach an estimated 260,000 barrels of oil per day in 2004. These plans are subject to Board of Directors and regulatory approval.

The company's long-term vision is to increase oil sands production to about 400,000 to 450,000 barrels of oil a day in 2008 through a combination of oil sands mining and in-situ development.

Proven and probable reserves

Annual estimates are made by Suncor of recoverable bitumen reserves associated with company surface mineable oil sand leases. The estimates are allocated between proven, probable and possible categories based upon criteria agreed to by management and reviewed by independent consultants. The proved reserves are considered to be conservative estimates in which there is a very high degree of

confidence. Probable reserves incorporate portions of the mine that have a lower drilling density and are expected to be recovered under current approvals for a period in excess of 30 years, if further expansions do not occur. There is at least a 50 per cent chance that the proved plus probable reserve estimates will be exceeded. The bitumen estimates are converted to synthetic crude estimates on the basis of yields currently being obtained.

Oil Sands has recognized **proven and probable reserves** of 476 million barrels and 2,028 million barrels, respectively, on the leases it currently has regulatory approval to mine.

Management believes that these reserves are sufficient to support Project Millennium's planned production target of 225,000 barrels per day for a period in excess of 30 years. This does not include any reserves for the Firebag in-situ heavy oil leases. Additional reserves will be recorded as Suncor completes further drilling and analysis on these leases.

Prior to mining additional leases, regulatory approval must be obtained. Accordingly, Suncor has not yet recognized as proven or probable reserves any of the resources on these additional leases. Management believes that, assuming estimated economies of scale and reliability improvements are achieved, Oil Sands could reduce the cash operating cost to about \$8.50 to \$9.50 per barrel in 2002 from the 1999 level of \$11.40 per barrel. Total operating costs, which include cash operating costs as well as non-cash costs, are targeted to be reduced to the \$11.65 to \$12.75 per barrel range from the 1999 level of \$14.75 per barrel.

Project Millennium

Construction of the \$2-billion second phase of Project Millennium began on schedule in the second quarter of 1999 after Suncor received Suncor Board of Directors and regulatory approvals.

Engineering on Project Millennium is expected to be completed by mid-year 2000. The project is on track for commissioning to begin in the third quarter of 2001, with full production targeted for the year 2002.

Risk/Success Factors Related to Project Millennium

In addition to potentially volatile crude prices, there are certain risks associated with the Project Millennium schedule, resources and costs. With competing projects in Alberta, there will be increased demand for labour and material and the associated risk of delay in material delivery and scheduled completion. The project management has developed a working relationship with the trade unions, including workshops and joint initiatives. The project schedule has been developed with recognition of the needs of competing projects. Projects of this magnitude can result in the final cost being higher or lower than original estimates. Management believes in the current environment that there are risks that Project Millennium costs could be higher than the original estimate.

In response to Suncor's Canadian Environmental Assessment Act process for Project Millennium, three non-governmental environmental organizations have challenged the federal Minister of Environment's decision to declare the project environmentally acceptable. This challenge is directed primarily at the federal assessment process rather than the project itself. Suncor continues to work with regulators, both provincial and federal, to ensure the project meets or exceeds all regulatory requirements.

The federal challenge is not expected to impact the construction of Project Millennium.

Leveraging Alliances to Support Oil Sands Expansion

In 1999, Suncor signed a long-term agreement with TransAlta whereby TransAlta will build, own and operate a cogeneration facility that will help meet a portion of Suncor's long-term energy needs at Oil Sands. As of October 1, 1999, TransAlta assumed operating responsibility for Suncor's existing energy plant. TransAlta announced plans to begin operating its new gas turbines commercially in the first quarter of 2000, and commissioning of other cogeneration equipment is expected to continue throughout 2000.

The April 1999 start-up of the Enbridge Athabasca Pipeline (owned by Enbridge Pipelines (Athabasca) Inc.) expanded Oil Sands' ability to ship to new markets. Suncor's agreement with Enbridge provides Suncor long-term pipeline access of up to 170,000 barrels per day. The pipeline has a potential capacity of up to 550,000 barrels per day. The pipeline provides a new transportation link between Fort McMurray and Hardisty, a major Alberta crude oil hub that connects onward to markets in the U.S. and Eastern Canada.

The Hydrocarbon Liquids Conservation Project based on an agreement between Suncor and Novagas Canada Limited Partnership, operating as TransCanada Midstream (TCM), received regulatory approval in 1999. This project is designed to extract and separate natural gas liquids and olefins from "off-gas," a byproduct of the oil sands upgrading process. The recovered liquids and olefins will be transported in batches via Suncor's Oil Sands Pipeline to TCM's Redwater, Alberta fractionation facility for further processing. Management believes the project will help to reduce sulphur dioxide emissions at Oil Sands as well as provide additional revenue for Suncor.

In April 1999, TransCanada Pipeline Ventures Limited Partnership (formerly NOVA Pipeline Ventures Limited Partnership) completed construction of its pipeline, which is anticipated to meet Suncor's foreseeable needs for transporting natural gas to its Oil Sands facility. Gas is now being delivered to the Suncor site via the new line.

Risk/Success Factors Affecting Overall Performance

The profitability of Suncor's Oil Sands business is influenced by crude oil prices, which are difficult to predict and impossible to control. Unplanned production or operational outages and slowdowns, particularly those related to severe climatic conditions, including those that affect quality of products produced, can be expected from time to time.

Suncor's relationship with its employees is important to its future success as work disruptions have the potential to adversely affect Oil Sands operations. Suncor entered into a new two-year collective agreement with the Communications, Energy and Paperworkers Union Local 707 effective May 1, 1999.

Exploration and Production



Overview

Suncor's Exploration and Production (E&P) business, based in Calgary, Alberta, explores for, acquires, develops, produces and markets natural gas, natural gas liquids, crude oil and various byproducts from the Western Canada Sedimentary Basin.

A significant factor impacting E&P's 1999 financial and operating results was a disappointing finding and development (F&D) program. E&P invested \$151 million to add six million barrels of new proved reserves. E&P's total proved reserves declined 37 million BOE to 152 million BOE as a result of property dispositions, downward technical revisions, and current-year production less new reserve additions. As a result, E&P's three-year F&D performance increased to \$11.40 per BOE from \$6.90 per BOE for the three-year period ending in 1998. The 1999 three-year average reserve replacement ratio was 120% compared with 200% for the three years ended 1998.

E&P initiated a portfolio optimization program in 1997 to improve the quality of its asset base and to improve its net cash position by selling non-strategic properties and assets. This program positively impacted 1999 financial results. Proceeds from the property dispositions contributed \$90 million towards the net cash surplus, an increase of \$81 million over 1998 levels. Property dispositions associated with the program represented annual production of 3,300 BOE per day. The program has generated proceeds of over \$110 million since its inception. E&P plans to continue the program in 2000 with a focus on divesting oil properties. The property divestments planned for 2000 could generate \$100 to \$200 million in proceeds.

In the fourth quarter of 1999, E&P initiated a strategic study to examine ways to improve the financial and operating performance of its natural gas business as well as focus on defining new and profitable opportunities for growth. The study is expected to be completed by the end of the second quarter 2000.

Results of Operations/ Investing/ Exploration Activities 1999 versus 1998

Exploration and Production – Summary of Results

(\$ millions unless otherwise noted)	1999	1998	1997
Revenue	306	290	302
Production (thousands of BOE* per day)	37.2	42.2	40.3
Average sales price (including the impact of hedging)			
Natural gas (\$/ thousand cubic feet)	2.44	1.95	1.93
Conventional crude oil (\$/ barrel)	20.94	20.14	22.75
Earnings	43	25	24
Cash flow provided from operations	172	167	162
Total assets	962	943	819
Capital and exploration expenditures	200	242	240

* BOE is a measure which converts gas to oil on the approximate long-term economic equivalent basis that 10,000 cubic feet of gas equals one barrel of oil.

Earnings Analysis

Earnings Increase by 72% on Asset Divestment Gains

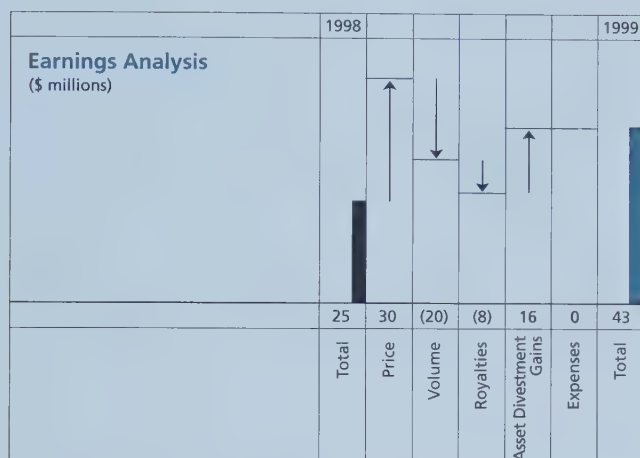
E&P's earnings increased to \$43 million in 1999, up 72% from \$25 million in 1998. During the year, cash flow from operations rose to \$172 million from \$167 million in 1998. The earnings increase was driven principally by a \$16-million increase in gains on asset dispositions and by stronger natural gas prices. The increase in cash flow from operations was mainly attributed to higher natural gas prices.

Natural Gas Prices increase 25%

In 1999, E&P's natural gas price averaged \$2.44 per thousand cubic feet (mcf) compared with \$1.95 per mcf in 1998, an improvement of 25%. Prices strengthened throughout the year as a result of stronger demand and improved access to export markets in the U.S. The 1999 price includes the impact

Reservoir

Body of porous rock containing an accumulation of water, crude oil or natural gas.



Price improvement and asset divestment gains more than offset the shortfall in production volumes resulting in the earnings improvement.

of E&P's hedging program, which decreased the price by \$0.04 per mcf.

E&P's average realized crude oil price increased \$0.80 per barrel, to \$20.94 per barrel in 1999, due to the increase in world oil prices. The price realized in 1999 was reduced by \$2.72 per barrel due to the impact of crude oil hedging. The increase in oil and gas prices, partially offset by hedging program losses, resulted in a net \$30-million increase in earnings compared with 1998.

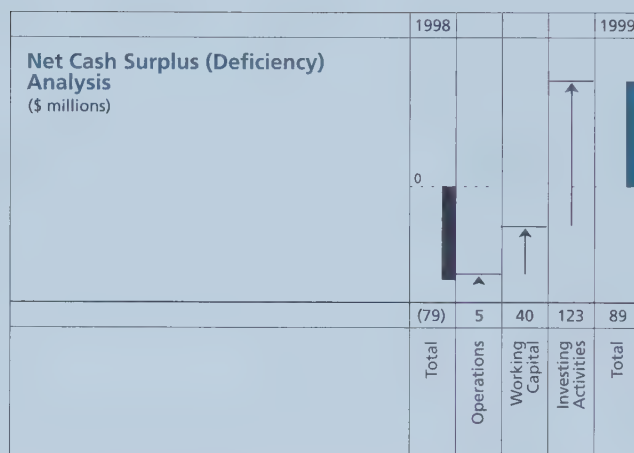
Production Declines 12% Over 1998 Level

E&P's oil and natural gas volumes declined to 37,200 BOE per day in 1999, from 42,200 BOE per day in 1998. The main factors for the production decline were asset dispositions (representing annual production of 3,300 BOE per day) combined with natural **reservoir** declines, disappointing drilling results and delays in bringing new production on stream.

The decline in volumes in 1999 over 1998 had a negative impact on earnings of \$20 million.

Royalties Increase with Higher Commodity Prices

Royalties increased to \$4.26 per BOE in 1999 from \$2.75 per BOE in 1998 mainly due to the significant increase in natural gas prices. The increase in royalties reduced earnings by \$8 million.



Lower capital and exploration spending and \$81 million in higher proceeds from property dispositions result in a \$168-million year-over-year improvement in E&P's net cash flow.

Total Expenses Remain at 1998 levels

Total cash expenses in 1999 were \$2 million lower than in 1998, mainly due to lower administrative costs. Depreciation, depletion and amortization expenses (non-cash) increased by \$2 million in 1999 over 1998 as a result of higher per-barrel, non-cash costs. The net result of lower administrative and higher non-cash costs was no net increase in year-over-year expenses.

Asset Divestment Gains

As part of E&P's ongoing portfolio optimization program, gains from the sale of non-strategic assets were \$19 million in 1999, a \$16-million increase as compared to 1998.

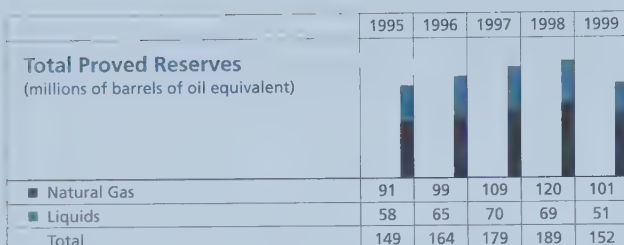
Net Cash Surplus Analysis

E&P had a net cash surplus of \$89 million in 1999, an improvement of \$168 million when compared to the deficiency of \$79 million in 1998. The improvement was driven by an increase in divestment proceeds of \$81 million, a reduction in capital and exploration investing activities of \$42 million, a \$40-million decrease in working capital and an improvement in cash from operating activities of \$5 million. The working capital improvement was due to inventory and other asset reductions, and an increase in accounts payable related to high year-end capital spending.

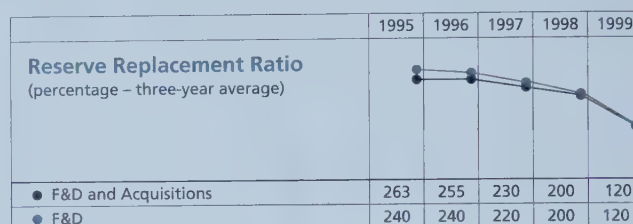
* This Section contains forward-looking information. Also refer to the Overview*** on page 21 of this report.

In-situ

In-situ or "in place" refers to methods of extracting heavy oil from deep deposits of oil sands without removing ground cover.



Poor drilling results, negative reserve revisions and higher than planned divestments result in a decrease in total proved reserves.



A disappointing drilling program and reserve revisions of 12.5 million BOE (7% of reserves at the beginning of the year) push three-year reserve replacement ratio to lowest level in last five years.

Capital and Exploration Investing Activities

E&P's net investing activities declined from \$233 million in 1998 to \$110 million in 1999. The decline in capital spending is a result of lower exploration and development drilling and lower lease and well equipment expenditures. Divestment proceeds increased \$81 million as a result of the ongoing portfolio optimization program. The decline in net investing activities was part of E&P's net cash flow management program supporting other Suncor growth initiatives.

Outlook*

Focus on Natural Gas

E&P has been increasing its natural gas focus for the past seven years, based on management's belief that commodity prices will strengthen and market access for natural gas will improve. The outlook for Alberta natural gas prices remains positive due to strong U.S. demand and further increases in export pipeline capacity. Suncor expects U.S. gas demand to continue growing, supported by improving industrial demand and increased use of natural gas in electricity generation.

Suncor's strategy is to continue to position its E&P business to benefit from any increase in Canadian natural gas prices. Through its portfolio optimization program, management will continue to evaluate the strategic fit of conventional oil properties. E&P will focus its exploration and production program on developing natural gas from the Western Canada Sedimentary Basin. The company will also continue its pursuit of coal bed methane resources in North America and Australia as a source of natural gas.

Suncor launched a comprehensive strategic review to determine ways to improve financial and operational performance and define new and profitable opportunities for growth. Further property divestments in 2000 could generate \$100 to \$200 million in proceeds. E&P's divestment program will consist mainly of the sale

of oil properties and reflects an increasing emphasis on natural gas. Suncor will use cash generated by the sales to support Project Millennium oil sands expansion and other growth projects. E&P's current goal is to achieve an average finding and development cost of \$6.75 per BOE for the year 2000 and profitably grow reserves and production.

In-situ Oil Sands

Suncor advanced its heavy oil strategy in 1999 by conducting additional delineation, engineering and cost assessments, and an initial review of environmental issues. In December, the company acquired an additional four oil sands permits in the Firebag area which, when combined with leases already held by the company, create one of the largest continuous landholdings in the Athabasca region at 785 square kilometres.

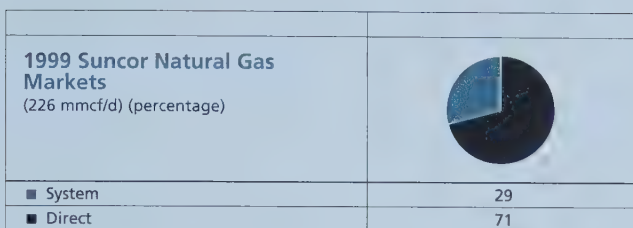
Subsequent to the end of 1999, Suncor announced plans to invest \$750 million in an oil sands expansion (see Oil Sands Outlook section). This expansion includes a proposed investment of \$450 million towards a commercial scale **in-situ** operation using steam-assisted gravity drainage (SAGD) on the company's Firebag leases north of Fort McMurray. The first phase of the project proposes to add 35,000 barrels of bitumen per day in 2004. Long-term plans call for further investment to increase in-situ production in stages to 140,000 barrels of bitumen per day by the end of the decade.

Management believes Suncor has several competitive advantages to develop its Firebag In-situ Oil Sands Project including the quality of its in-situ leases, the ability to upgrade bitumen and access other infrastructure efficiencies at its Oil Sands facilities, and the opportunity to apply knowledge gained from operating the Burnt Lake pilot project.

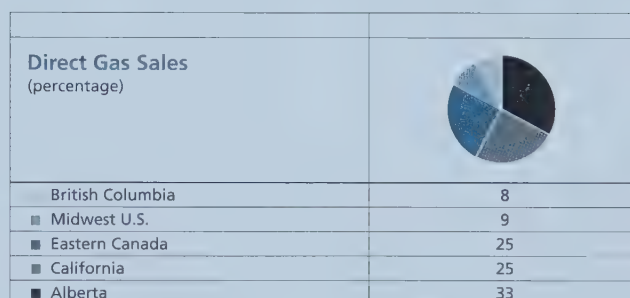
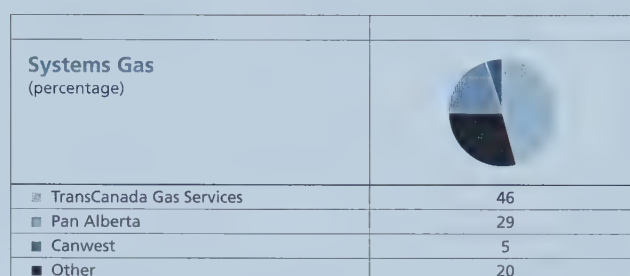
The Burnt Lake pilot project achieved a milestone in 1999, producing its millionth barrel of bitumen. Burnt Lake completed its third full year of production in 1999, producing 1,500 barrels

Carbon Sink

A pool (reservoir), such as forests or soils, that absorbs or takes up released carbon from another part of the carbon cycle (i.e. from the atmosphere).



E&P believes its gas portfolio is positioned to take advantage of improved Alberta pricing fundamentals.



per day (Suncor's share of this production was 1,200 barrels per day). The successful application of SAGD technology at Burnt Lake has given Suncor the confidence to invest in a commercial application of the technology at Firebag. The company continues to look at all options to optimize the value of Burnt Lake, including the possible sale of the property.

Evaluating Coal Bed Methane Opportunities

In 1998 Suncor began evaluating coal bed methane opportunities in North America and Australia. The company is also participating in research and development initiatives to investigate the potential of coal beds to sequester carbon dioxide. These initiatives are directed towards capturing the potential that subsurface coal provides as a source of natural gas and a potential "carbon sink" for greenhouse gas emissions.

In the fourth quarter of 1999 the company's application to explore natural gas resources in the Australian state of New South Wales was approved. The petroleum exploration licence gives Suncor the right to develop coal bed methane and other petroleum resources on over a million acres in the northeastern region of New South Wales. Over the next two years, Suncor will review technical data, conduct seismic work, drill wells and assess gas markets to evaluate the opportunity.

In addition to pursuing coal bed methane in Australia, Suncor is evaluating opportunities in North America.

Suncor's Active Investigation into South American Opportunities Completed

Suncor has completed the investigation into conventional oil and natural gas opportunities in South America. The company's focus on its oil sands expansion and its current natural gas business contributed to a decision to conclude current efforts. The company may reactivate its investigation into natural gas exploration and production opportunities in South America in the longer term.

Risk/Success Factors Affecting Performance

The risks associated with Suncor's natural gas and crude oil activities and commodity pricing should not be underestimated or viewed as predictable. Suncor expects that both natural gas and crude oil pricing will continue to be volatile due to the cyclical nature of supply and demand for these commodities. Management continues to believe the single most important factor that will influence E&P's long-term performance is its ability to consistently and competitively find and develop low-cost, high quality reserves that can be economically brought on stream. Market demand for land and services can also increase or decrease finding and development costs. Management believes there are risks and uncertainties associated with obtaining regulatory approval for exploration and development activities. Working in other countries could increase these risks and add to costs or cause delays to these projects. The company works to reduce these risks through proactive consultation with stakeholders.

Sunoco



Overview

Suncor's wholly owned subsidiary, Sunoco Inc., has three Ontario-based business divisions: Refining (including wholesale sales), Retail Marketing and Integrated Energy Solutions.

Located in Sarnia, Ontario, Sunoco's refinery is "complex" because it has the flexibility to produce a high proportion of transportation fuels and petrochemicals. This refinery has capacity to refine 70,000 barrels of crude oil per day. For the past three years, the refinery has utilized 95% or higher of its crude refining capacity. The refinery's average utilization rate in 1999 was 95% (1998 – 99%). In 1999, sales of refined products averaged 86,800 barrels per day.

Sunoco sells approximately 87% of its total refined product volume in the Ontario market, which is its primary market. In 1999, Sunoco's share of total refined product sales in Ontario was approximately 16% (1998 – approximately 17%).

The majority of production from the Sarnia Refinery, including approximately 93% of gasoline production, is marketed through Sunoco-controlled distribution channels in five distinct markets. The remaining production is sold to wholesale and industrial accounts in Ontario and Quebec.

Sunoco's controlled distribution channels include:

- 305 Sunoco retail service stations in Ontario, located primarily along the main Windsor-Kingston-Ottawa transportation corridors;
- 156 Pioneer-operated retail service stations in Ontario (the Pioneer Group Inc. is an independent retailer with whom Sunoco has a 50% joint venture partnership);
- 60 UPI-operated service stations in rural Ontario; UPI Inc. is a 50% joint venture company owned by Sunoco and GROWMARK Inc. (a large U.S. Midwest agricultural supply and grain marketing cooperative). UPI sites sell conventional and ethanol-blended gasolines, diesel and heating oil to residential, commercial and farm customers;

- Eight Sunoco diesel Fleet Fuel Cardlock sites in southern Ontario; and
 - Sun Petrochemicals Company, a 50% joint venture between Sunoco and U.S.-based Sunoco, Inc.'s (an unrelated company) refinery in Toledo, Ohio. The joint venture markets an average of 15,150 barrels of petrochemicals per day worldwide.
- Sunoco's Integrated Energy Solutions business, launched in 1997, sells natural gas to Ontario homeowners and commercial customers and offers heating, ventilation and air conditioning (HVAC) products and services through 29 dealers.

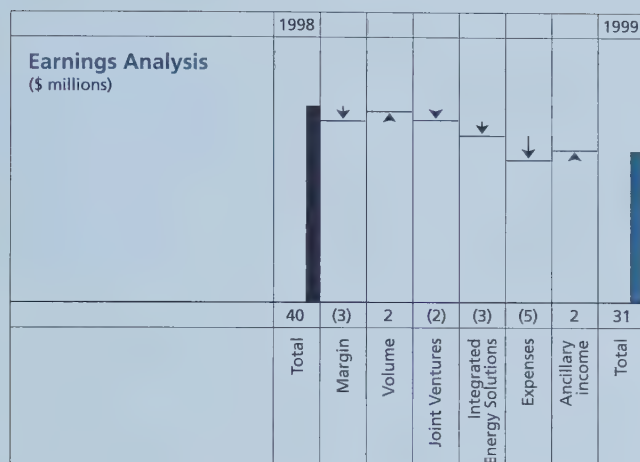
Results of Operations and Investing Activities 1999 versus 1998

Sunoco Results Summary

(\$ millions unless otherwise stated)	1999	1998	1997
Revenue	1 779	1 533	1 673
Refined product sales (thousands of cubic metres)			
Retail gasoline	1 500	1 496	1 387
Total	5 080	5 037	5 182
Earnings (loss) breakdown:			
Refining/wholesale	13	24	34
Retail marketing	22	17	10
Energy marketing	(4)	(1)	(5)
Total	31	40	39
Cash flow provided from operations	103	112	121
Investing activities	43	64	55
Net Cash Surplus	129	55	30

Ancillary Revenue

Revenue earned from such activities as car washes, sale of fast foods and confectionary items.



Increasing crude oil and feedstock prices over the year that could not be fully recovered in the marketplace and mild winter conditions combined to reduce refining earnings. The lower refining earnings and higher loss in the Integrated Energy Solutions business were responsible for the earnings decline.

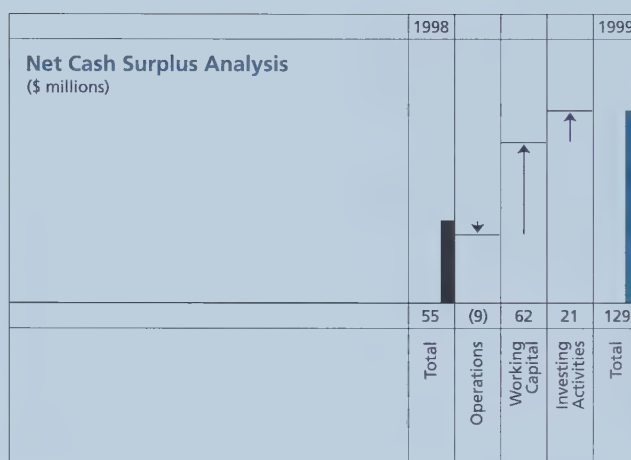
Earnings Analysis

Earnings Down \$9 million Compared with 1998

Sunoco's 1999 earnings were \$31 million compared with \$40 million in 1998. This decrease is largely attributable to lower refining margins caused by high product inventories at the beginning of the year and quickly rising crude oil prices which could not be fully recovered in the marketplace, although margins improved in the second half of the year. Refining earnings were also negatively impacted by higher feedstock costs. Higher Integrated Energy Solutions losses also contributed to the earnings decline. Retail margins, however, were stronger in 1999 compared to 1998, and earnings from sales of non-petroleum ancillary products increased, partially offsetting the effect of lower refining margins.

Reduced Refining Margins Impact Refining Profitability

Earnings from refining activities declined to \$13 million in 1999 compared with \$24 million in 1998, primarily because Sunoco's refining margin decreased to an average of 4.0 cents per litre (cpl) in 1999 compared with 4.1 cpl in 1998. This factor alone reduced year-over-year refining earnings by \$5 million. Rapidly rising and volatile crude prices and high international inventories of crude and petroleum products combined to reduce refining margins early in the year. Sunoco's refining margins improved in the last half of the year as global inventories declined. The earnings decline was positively impacted by a \$2-million improvement over 1998 due to higher wholesale gasoline and distillate sales volumes. Earnings from Sun Petrochemicals Company joint venture were down \$2 million from 1998 due



Accounts receivable and inventory reductions were the primary factors contributing to the \$74-million improvement in cash flow.

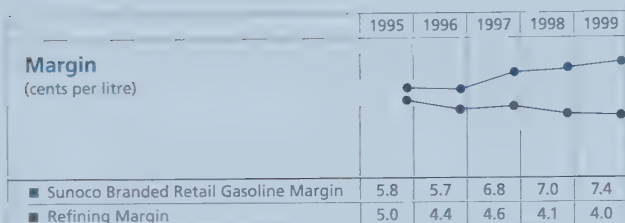
largely to weaker margins. Also contributing to the earnings decline were expenses that were \$6 million higher than in 1998. The increase was due to higher energy costs, additional purchases to cover demand due to lower crude runs, and fourth quarter operational outages.

In 1999, Sunoco confirmed its ten-year agreement signed in 1998 with NOVA Chemicals (Canada) Ltd. to further optimize both companies' Sarnia-based operations through the exchange of feedstocks and finished products.

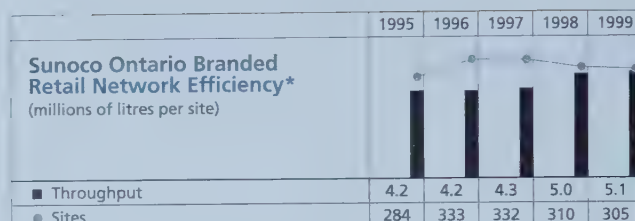
Retail Marketing Earnings Up 29% Over Last Year

Sunoco's retail marketing division achieved its best earnings in over 11 years – \$22 million in 1999 compared with \$17 million in 1998. Earnings from Sunoco's retail networks improved primarily due to an increase of \$2 million in gasoline margins from Sunoco's branded retail network (7.4 cpl in 1999 compared with 7.0 cpl in 1998), a \$2-million increase in **ancillary revenues** and a \$1-million reduction in expenses.

Based on independent market survey data, Sunoco retained its market share of 18.5% in the overall Ontario retail gasoline market in 1999. Independent survey data shows that Sunoco's branded retail network continues to be in the top decile of all Ontario retailers as measured by throughput per site. Sunoco's customer loyalty program with the Canadian Automobile Association's Ontario clubs gained popularity among customers with an increased number of CAA Ontario members using their *swipe-and-save cards* at Sunoco retail sites since 1998. Retail marketing initiatives to broaden Sunoco's non-petroleum offering of products and services, such as Country Style



Retail margins improved year-over-year while refinery margins saw a decline in the first half of the year. The decline was partially offset by a recovery in the second half of the year.



* Throughput per site – Millions of litres per site based on the average number of sites at the beginning and end of the year.

Sites – Number at year-end, excluding joint-venture-owned sites.

Site throughput increased 2% over 1998 due to efforts to improve efficiency and a net reduction in the number of sites.

branded coffee, resulted in a 21% improvement in ancillary revenues in the year.

Sunoco Expands Home Energy Dealer Network

Sunoco's Integrated Energy Solutions business had a loss of \$4 million in 1999 compared with a loss of \$1 million in 1998. The higher loss was primarily due to floating rate contractual sale price commitments that were less than the cost of supply of natural gas.

The Ontario Energy Board has recently approved Sunoco's proposal to convert its floating rate customer contracts to fixed rate contracts effective July 2000. This change should improve Sunoco's ability to make a positive margin in its natural gas business.

As part of its goal to broaden its energy offerings, Sunoco expanded the number of dealer members in the Home Energy Dealer Network to 29 dealers in just over one year's time.

Net Cash Surplus Analysis

Net cash flow increased to \$129 million in 1999 compared with \$55 million in 1998. Cash flow from operations decreased to \$103 million compared with \$112 million in 1998, primarily as a result of lower margins from the Sunoco refining operations.

Working capital improved by \$62 million primarily due to the reduced amounts of accounts receivable and crude oil inventory. Capital spending decreased to \$43 million compared with \$64 million in 1998.

Outlook*

Emphasis on Refinery Competitiveness

The competitive plans of the refinery include a goal of being rated in the top third of North American refineries of the same size and complexity – in profitability and efficiency, as reported

by independent survey data. The target date for the refinery to achieve this goal has been moved to 2002 from 2000, due in part to the delay of the Sarnia regional cogeneration project. Sunoco continued implementing the refinery organizational realignment it launched in 1997 with 90% completion planned for the end of 2000. Overall, these initiatives are designed to reduce refining costs, which in turn should have a positive impact on Sunoco's earnings.

Sunoco continues to evaluate its participation in TransAlta Energy Corporation's proposed Sarnia regional cogeneration project. Such involvement will be subject to enabling rules and regulations emanating from the Ontario government's electricity deregulation process. These include acceptable transmission tariff structures currently under a rate hearing by the Ontario Energy Board. Due to the length of the deregulation process, the start-up is now estimated to be mid-2002.

In 1999, Sunoco's refinery achieved ISO 14000 certification, an accreditation that endorses effective environmental management systems based on international standards. The Sunoco refinery was the first refinery in Canada and the fourth in North America to be certified. This is consistent with Suncor's goal of leadership in the areas of environment, health and safety and aids in effective environment risk management.

Expansion of Diesel Markets

In 1999, Sunoco continued to expand its offering to the on road diesel market by adding three additional sites to its Fleet Fuel Cardlock network. The cardlock margin adds value over traditional distribution channels. Sunoco will continue its plans for cardlock network growth that were initiated in 1998. Marketing efforts focused on a premium diesel fuel, Gold Diesel, with Sunoco more than doubling the volume sold in 1999 compared to 1998.

Retail Marketing Continues to Develop Through Strategic Associations

Sunoco-branded retail marketing continues to focus on differentiating itself by implementing its vision of becoming the neighbourhood choice for energy, comfort and convenience retailing in Ontario. Management believes Sunoco's relationships with retailers, suppliers, customers and communities facilitate potential revenue growth and an enhanced understanding of stakeholder requirements.

Ancillary revenue from non-petroleum products grew 21% in 1999 due to marketing programs and capital improvements in the business that added and improved facilities to support marketing initiatives.

The company's exclusive five-year loyalty program signed January 1, 1999 with the Ontario clubs of the CAA provides Sunoco access to the association's 1.8 million members to market retail gasoline, natural gas and other products and services.

Joint Marketing Initiatives Planned for Integrated Energy Solutions (IES) and Retail

Sunoco launched its retail natural gas marketing business in 1997 to take advantage of opportunities in the broader energy market in Ontario resulting from deregulation. Due to delays in the regulatory process, IES has shifted its focus from aggressive growth to retention and extension of new products and services to Sunoco's existing customer base. IES and retail marketing piloted several joint marketing initiatives in 1999 to capitalize on integration opportunities. Additional programs are planned in 2000, including an expanded customer loyalty program and development of internet marketing, which are being designed to attract more customers to buy more Sunoco products more often.

In addition, Sunoco continues to assess the potential for marketing electricity in Ontario, a new growth opportunity resulting from the pending deregulation of electricity services in the province.

Risk/Success Factors Affecting Performance

Margin and crude oil price volatility and overall marketplace competitiveness, compounded by a warm winter and higher petroleum product inventories, reduced margins in 1999. In the last half of 1999, crude prices increased rapidly, resulting in refining margin volatility. Management expects that fluctuations in demand for refined products, margin volatility and overall marketplace competitiveness will continue. As Sunoco participates in new product markets – such as natural gas, and

potentially electricity – it could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

The Canadian refining industry faces significant capital spending to construct sulphur removal facilities following the passage of legislation that limits sulphur levels in gasoline to an average of 150 parts per million (ppm) from mid-2002 to the end of 2004, and a maximum of 30 ppm by 2005. Although the spending required to meet the new standards could be significant, Sunoco believes it will not be material to Suncor on a consolidated basis and that compliance spending will not put Sunoco at a competitive disadvantage.

A Sunoco task force has completed a strategic study of the implications of fuels reformulation, technical alternatives, and technological change for the industry in general and on Sunoco in particular. As a result of the study, management believes Sunoco will be positioned competitively in the future.

Sunoco's refinery has complied with more stringent national standards for cleaner-burning gasolines, including limits on benzene emissions, which came into effect on July 1, 1999, with minimal capital spending.

Environmental Responsibility

Sunoco continues to focus on and address environmental issues facing Ontario and Canada. In 1999, Sunoco introduced a new gasoline additive that reduces nitrogen oxides (NOx) from tailpipe emissions. This initiative generated over 275 tons of NOx credits under Ontario's Pilot Emission Reduction Trading project. Sunoco then sold the credits to Ontario Power Generation Inc. and intends to use a portion of the proceeds from the emissions trade to fund additional pollution prevention projects.

In 1999 Sunoco increased the percentage of ethanol in gasoline sold at all Sunoco-branded retail sites. Ethanol-enhanced gasoline reduces carbon monoxide and greenhouse gas emissions compared with conventional gasoline. Sunoco's gasoline and car washes are certified to display Environment Canada's EcoLogo certification, which demonstrates active commitment to offering products and services which meet Canada's environmental labelling guidelines.

Corporate



Overview

Suncor's Calgary corporate centre fulfills a number of roles, including support to the company's business units and Board of Directors. Corporate centre personnel are accountable for functions such as legal, taxation, risk management, company-wide human resource programs, treasury, corporate finance, planning and business development, corporate communications and regulatory reporting at the corporate level.

Results of Operations and Investing Activities 1999 versus 1998

Corporate expenses increased from \$27 million in 1998 to \$48 million in 1999, mainly due to higher taxes (\$11 million) and higher costs related to Suncor's **long-term incentive plan** (\$10 million).

The corporate centre had a net cash deficiency of \$73 million in 1999 compared to a net cash deficiency of \$198 million in 1998. The \$125 million reduction in cash deficiency was primarily due to a \$74-million reduction in investing activities in 1999 due to the completion of construction of the Stuart oil shale demonstration plant in Australia (also see note 12(b) to the financial statements) and a reduction in working capital. The decrease in working capital was associated with hedging losses, higher income taxes and increased operational payables.

Consolidated Balance Sheet Analysis

Higher commodity and refined petroleum product prices at the end of 1999 compared to the end of 1998 were the primary factors for a \$101-million increase in accounts receivable. The impact of higher prices was partially offset by the **sale** of a portion of accounts receivable.

An inventory decrease of \$14 million was due to the reduction of a portion of the company's crude oil inventory and the sale of some midstream natural gas equipment. The benefit of these

sales was partially offset by an increase in Oil Sands inventory related to the start-up of the Enbridge Athabasca Pipeline and a temporary increase in year-end inventories at Oil Sands.

Net capital assets increased by over \$1 billion in 1999 with \$941 million of the increase coming from Suncor's Project Millennium and the Stuart Oil Shale Project in Australia. Capital assets are reduced by depreciation, depletion and amortization once they are placed into service. In 1999 capital assets with a net book value of \$58 million were sold and this reduced net capital assets. The majority of assets disposed of were associated with E&P's divestment program.

Trade payables and accrued liabilities were \$322 million higher in 1999 than in 1998. A major factor in this increase was the activity level associated with Project Millennium, which accounted for approximately \$190 million of this increase. Higher crude oil and natural gas prices at the end of 1999 compared with year-end 1998 and higher sales volumes in Oil Sands resulted in higher royalties and hedging payables. The higher crude oil prices also increased the cost of crude oil and other feedstocks purchased in Suncor's downstream business. These purchases were higher than in 1998 due to an operational problem at the Sarnia Refinery late in 1999 that required the purchase of finished product to ensure that all customer requirements were met.

Excluding cash and short-term borrowings and the current portion of long-term borrowings, Suncor had a working capital deficiency of \$225 million at the end of 1999 compared to a surplus of \$22 million at the end of 1998. Over 80% of the \$247-million change was due to Project Millennium spending and hedging activities. Suncor had in place unused lines of credit of \$1.2 billion at the end of 1999. These unused lines of credit expire at the end of 2004.

The increase in 1999 of deferred income taxes resulted primarily from income tax deductions associated with certain capital investments at Oil Sands and the Stuart Oil Shale Project.

Consolidated Earnings Analysis

Sales and other operating revenues increased from \$2,068 million in 1998 to \$2,383 million in 1999. The impact of higher commodity prices increased revenues by \$321 million. This figure is after the impact of hedging activity undertaken in 1999. While crude oil sales volumes increased due to record Oil Sands sales levels, a decrease in conventional liquids and natural gas volumes resulted in a \$6-million negative impact on revenue.

The impact of higher crude oil prices in 1999 was also reflected in Suncor's purchases of crude oil and products, which increased by \$153 million in 1999. Crude oil, other feedstocks and products purchased by Sunoco's Sarnia Refinery increased by \$157 million in 1999 while Oil Sands decreased its purchases of bitumen from third parties by \$4 million. The increase in purchases at the Sarnia Refinery primarily reflects the impact of higher market prices in buying from third parties. This increase was also affected by production interruptions in the fourth quarter at the Sarnia Refinery that necessitated refined product purchases to meet customer requirements.

Operating, selling and general expenses increased \$68 million from \$682 million in 1998 to \$750 million in 1999. Higher operating costs in all operations represented \$53 million of the year-over-year increase. The higher operating costs were primarily a result of higher mining and extraction costs at Oil Sands, higher unit operating costs in the E&P business and higher operating expenses at Sunoco's Sarnia Refinery. These higher operating costs were partially offset by lower volume-related expenses in E&P (\$7 million). Expenses were also increased by \$22 million due to a higher provision for employee incentive plan costs in 1999.

Royalty expenses increased \$21 million, to \$99 million in 1999. Higher commodity prices increased royalties by \$31 million. A combination of lower conventional oil and natural gas volumes and a change in sales mix at Oil Sands decreased royalties by \$10 million. The change in sales mix is a result of a planned partial maintenance shutdown that resulted in the production of only sour crude oil for one month at Oil Sands. There is no planned Oil Sands maintenance shutdown work in 2000.

Taxes other than income taxes increased by \$9 million due to higher sales volumes of taxable products (mainly transportation fuels) in the downstream business (\$7 million). Higher property taxes in Oil Sands due to the increased property tax base with the expansion of operations in late 1998 increased costs by \$2 million.

Depreciation, depletion and amortization (DD&A) increased in 1999 over 1998 by \$54 million, to \$318 million. The increase was largely due to increased DD&A costs at Oil Sands.

Higher depreciation was due to a higher capital base resulting from the completion of Oil Sands' Steepbank Mine and fixed plant expansion in late 1998. DD&A was also higher at Oil Sands due to higher overburden amortization (\$30 million). This overburden amortization increase reflects the impact of three factors: a 17% increase in Oil Sands production; an increase in the estimated amount and cost of overburden removal; and the impact of ceasing mining activity on the original oil sands leases sooner than anticipated. The impact of closing the original mine earlier than planned and the resulting reduction in reserves, is to increase the amortization of overburden associated with the original mine by \$7 million per year for about a year. This increase in the write-off is due to a 20-million-barrel reduction in reserves.

Net financing costs were unchanged year-over-year as additional interest income was offset by higher borrowing costs in the first half of 1999 compared to 1998. 1999 capitalized interest costs exceeded the 1998 level. The increase in interest capitalized is due to the spending on Project Millennium.

The effective tax rate increased from 37% in 1998 to 40% in 1999. This reflects the refund of \$11 million received in 1998. Excluding the refund, 1998's rate would be approximately 41%.

Outlook*

Growth Priorities

In 1998's MD&A, Suncor outlined its six long-term growth priorities. As a result of continued review and assessment, the company has consolidated its growth priorities to a total of four. In order of priority, they are:

1. Expand Oil Sands production. In 1999 Suncor received regulatory approval for the second phase of its \$2.2-billion Project Millennium. The company commenced the first phase in 1998, called the Production Enhancement Phase (PEP). Phase 2 commenced in 1999 with the receipt of regulatory approval. Combined, these two phases are designed to increase Oil Sands production to 225,000 barrels per day in 2003, from the 1999 production of 105,600 barrels per day.

In 2000 Suncor announced a plan to further expand its oil sands facilities beyond 2003 with a proposed investment of \$750 million in an in-situ project and a further expansion of the oil sands plant. The in-situ portion of the project is scheduled to be integrated with Suncor's open pit mining operation, and, combined with plans to expand upgrading capacity, would enable output from Suncor's plant to reach an estimated 260,000 barrels of oil per day in 2004. In-situ

Sequestration of Carbon Dioxide
The storage of carbon in large-scale carbon sinks, such as forests or underground reservoirs, that reduce greenhouse gas concentrations in the atmosphere.

technology recovers bitumen with less impact to the air, water and land than traditional mining methods and allows Suncor to develop oil sands deposits not accessible through open pit operations. Potential advantages of the current plans to integrate the in-situ project with the existing oil sands plant include:

Minimal disruption of land. The physical plant structure will disturb less than 10% of the surface land area over the deposit being developed.

Self-sufficient water use. The water used in the operation will be recycled and will come from the waste water streams from Suncor's oil sands plant.

Steam generation fuelled by natural gas. The SAGD process will be fuelled by natural gas which is the cleanest burning fossil fuel.

Enhanced recovery research. Suncor is conducting research into the potential of injecting carbon dioxide and light hydrocarbons into the in-situ deposit to decrease the amount of the steam needed, thereby further reducing emissions.

Potential for carbon sequestration. Suncor will examine the potential use of the in-situ reservoir as a permanent repository to inject greenhouse gas emissions.

These plans are subject to Board of Directors and regulatory approval.

The company's long-term vision is to increase oil sands production to about 400,000 to 450,000 barrels of oil a day in 2008 through a combination of oil sands mining and in-situ development. The company has not yet identified specific plans to achieve this vision, and any such plans would be subject to Board of Directors and regulatory approval.

2. Transfer Oil Sands technology and expertise to new businesses.

Suncor is pursuing growth opportunities in surface mineable oil deposits (both sand and shale). Prior to the end of 1999, Suncor had completed construction of a demonstration plant at the Stuart Oil Shale Project in Australia. The first phase of this project is designed to test the commercial viability of producing oil from oil shale. Operational testing and commissioning work is now under way, but has proven to take longer than initially expected. Hot commissioning trials have demonstrated that oil can be produced from oil shale, but further assessment is required to determine whether the technology is commercially viable. This decision is expected to be made by the end of 2000. Also refer to note 12(b) to the financial statements for further information with respect to this project.

The company is also assessing potential oil shale deposits in a number of other geographic locations, including Jordan and Estonia.

3. Further integrate Suncor's upstream and downstream businesses,

including potential expansion of the company's refining and marketing presence. In 1999 Suncor continued to actively evaluate several approaches to secure markets and transportation for its increasing Oil Sands production, including joint ventures, possible acquisitions, or long-term agreements with other refiners in both Canada and the United States.

4. Focus on Natural Gas and Alternative and Renewable Energy

Suncor intends to further strengthen its emphasis on natural gas exploration and development as it reduces its interests in conventional crude oil assets. As Suncor works to grow its natural gas business in Western Canada, it will also assess potential opportunities for the production of natural gas from coal bed methane, both in North America and internationally.

In addition, as the company develops its fossil-fuel-based businesses, management believes that Suncor also needs to work concurrently toward the development of alternative and renewable sources of energy. Early in 2000, Suncor announced plans to invest \$100 million in alternative and renewable energy projects over the next five years. The money is likely to be spent on research and development projects and commercial ventures which could include investments in producing fuel from biomass conversion of municipal solid waste to energy, recovering methane from landfills and capturing and sequestration of carbon dioxide. Suncor plans to examine potential opportunities in solar and wind power.

Risk/Success Factors Affecting Performance **Oil Sands**

When Project Millennium is completed, an even greater portion of Suncor's future financial performance is expected to be linked to the performance of its Oil Sands operations. Project Millennium is designed to increase Oil Sands production to 225,000 barrels per day in 2003. This business division would then account for over 80% of Suncor's upstream production compared to 72% in 1990. Suncor's cash operating cost at Oil Sands is expected to fall from its 1999 level of \$11.40 per barrel to the \$8.50 to \$9.50 per barrel range in 2002. Suncor believes that the planned increases in Oil Sands production present strategic advantages as well as issues that require prudent risk management. The strategic advantages of Oil Sands growth may include:

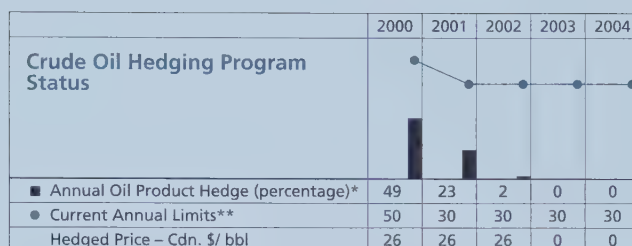
- Economies of scale associated with higher levels of production from the existing Oil Sands infrastructure;
- Lower unit costs and improved reliability;
- The ability to leverage demonstrated operational experience and technologies; and
- Production growth without the exploration risk associated with conventional oil and gas operations.

The issues that Suncor must manage include, but are not limited to:

- Suncor's ability to finance Oil Sands growth in a volatile commodity pricing environment (also refer to the section on Liquidity and Capital Resources, page 39.);
- Competition from new entrants in the oil sands business. This could take the form of competition for skilled people, increased demands on the Fort McMurray infrastructure (housing, roads, schools etc.), or higher prices for the products and services required to operate and maintain the plant. Suncor is addressing this issue by developing a comprehensive recruiting strategy, working with the community to determine infrastructure needs, designing oil sands expansion to reduce unit costs and capitalize on technology advancements, and seeking strategic alliances with service providers;
- Potential changes in demand for synthetic crude oil. Suncor believes it can reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding its customer base and offering customized blends of synthetic crude oil to meet customer specifications;
- Operational reliability;
- Regulatory and/or governmental change; and
- Preservation and protection of the environment. Suncor has an Environment, Health and Safety policy designed to mitigate the impact of its operations on the environment.

Commodity Prices

Suncor's future financial performance remains closely linked to hydrocarbon commodity prices, which can be influenced by global and regional supply and demand factors, worldwide political events and the weather. This can result in a high degree of price volatility, as occurred when benchmark crude oil prices increased by 131% from December 1998 to December 1999. Suncor has partially offset the impact of crude oil price volatility by reducing cash costs and improving reliability at Oil Sands over the past five years. Because prices of crude oil and natural gas are based on a U.S. dollar benchmark, Suncor's earned prices are influenced by the Canadian/U.S. currency exchange



* Percentage of annual crude oil production hedged as of December 31, 1999.

** Current annual limits for hedged volumes/dollars authorized by Board of Directors (percentage).

Suncor uses hedging as a risk management tool to reduce earnings and cash flow volatility. The annual limits may change, subject to Board approval, to reflect management's ongoing assessment of the risk it is willing to accept. Refer to note 15 in the consolidated financial statements for additional information.

rate, creating another element of uncertainty. The weakness in the Canadian dollar versus the U.S. dollar in 1999 increased Suncor's revenues as measured in Canadian dollars. In the future, the strength of the Canadian dollar relative to foreign currencies could create uncertainties for Suncor as it pursues its international growth plans. For example, a one-cent change in the Canadian/Australian exchange rate on the Stuart Oil Shale borrowings (see note 8 to the financial statements) will impact Suncor's pre-tax earnings by approximately \$1 million.

Hedging

Suncor cannot control the prices of crude oil or natural gas, or currency exchange rates. However, the company has a hedging program that fixes the price of crude oil and natural gas and the associated foreign exchange for a percentage of Suncor's total production volume. Suncor's objective is to lock in prices on a portion of the company's future production today to reduce exposure to market volatility and ensure the company's ability to finance its growth.

The Board of Directors meets with management regularly to assess Suncor's hedging thresholds in light of its price forecast and cash requirements. To add assurance to Suncor's ability to finance its 2000 capital program, the Board authorized hedging 50% of its crude oil volumes in 2000, with the authorized limit returning to 30% in 2001, 2002, 2003 and 2004. For natural gas, the Board has authorized a hedging program that allows up to 50% of Suncor's volume to be hedged in the current year and subsequent year, 30% for the third year, and 15% for the fourth year.

In 1999, crude oil, natural gas and currency exchange hedging activities decreased Suncor's earnings by \$56 million. In 1998, hedging activities increased earnings by \$47 million.

Other Factors

Other critical factors affecting Suncor's financial results include: volumes of refined product sales; margins on the sale of refined products; the success of the exploration program; interest rates; and the company's ability to manage costs. Also refer to the note (***) on page 21 of the MD&A.

Year 2000 Results

Suncor and its subsidiaries did not experience any material adverse consequences as a result of the changeover from the year 1999 to 2000 and the rollover to February 29, 2000.

As of the end of 1999, the total cost of the company's Year 2000 Project was \$25 million, of which \$11 million was incurred in 1999. Substantially all costs were recorded as expenses in Suncor's 1999 Statements of Earnings. The company does not separately track the internal costs incurred for its Year 2000 Project, such costs principally being the related payroll costs for information technology personnel.

Sensitivity Analysis

The sensitivity analysis shows the main factors affecting Suncor's annual pre-tax cash flow from operations and after-tax earnings based on actual 1999 operations, including the impact of hedging activity. The table below illustrates the potential financial impact of these factors applied to Suncor's 1999 financial results. A change in any one factor could compound or offset other factors. Because this table does not incorporate potential cross-relationships, the analysis is not necessarily accurate.

Sensitivity Analysis

(\$ millions)	1999 Average	Change	Approximate change in	
			Pre-tax cash flow from operations	After-tax earnings
Oil Sands				
Price of crude oil (\$/barrel)	23.84	U.S.\$1.00	31	18
Sales (barrels per day)	102 200	1,000	6	4
Exploration and Production				
Price of crude oil (\$/barrel)	20.94	U.S.\$1.00	6	3
Price of natural gas (\$/thousand cubic feet)	2.44	0.10	7	4
Production of natural gas (millions of cubic feet per day)	226	10	7	4
Sunoco				
Retail gasoline margin (cents/litre)	7.4	0.1	2	1
Refining/wholesale margin (cents/litre)	4.0	0.1	5	3
Consolidated				
Exchange rate: C\$: U.S.\$	0.67	0.01	12	7
Interest rate	5.2%*	1%	9	5

* Borrowings with interest at variable rates averaging 5.2% at December 31.

Environmental Regulation Risk/Success Factors

Environmental legislation affects nearly all aspects of Suncor's operations. These regulatory regimes are laws of general application that apply to Suncor in the same manner as they apply to other companies and enterprises in the energy industry. They require Suncor to obtain operating licences, and they impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments are required before initiating most new major projects or undertaking significant changes to existing operations.

In addition to these specific, known requirements, Suncor expects further changes will likely be required to preserve and protect the environment and quality of life. Some of the issues under discussion include possible cumulative impacts of oil sands development in the Athabasca region; the need to reduce or stabilize various emissions; potential impacts of government regulation as it relates to the reduction of greenhouse gas emissions; land reclamation and restoration; Great Lakes water quality; and reformulated gasoline and diesel to support lower vehicle emissions. Changes in regulation could have a potentially adverse effect on Suncor from the standpoint of product demand, product formulation and quality, and methods of production and distribution. For example, cleaner-burning fuels may be mandated, causing additional costs, which may or may not be recoverable in the marketplace. The complexity and breadth of these issues make it extremely difficult to predict their

Net Debt

Includes long-term borrowings, the current portion of long-term borrowings, short-term borrowings less cash and cash equivalents.

future impact on the company. Management anticipates capital expenditures and operating expenses will increase in the future in part as a result of the implementation of new and increasingly stringent environmental regulations.

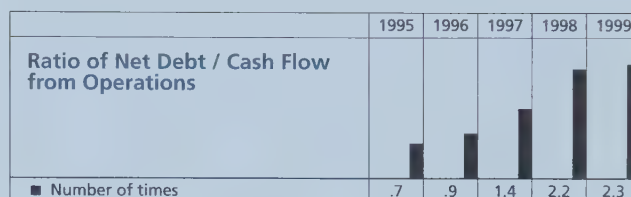
Liquidity and Capital Resources

Suncor's growth initiatives have increased **net debt** from \$796 million in December 1997 to \$1.3 billion at December 1999. Capital investment in the next three years, which includes spending for Project Millennium, is expected to be over \$3 billion, a similar level to the last three years.

Suncor management believes that it has sufficient borrowing capacity to fund Project Millennium and that cash flow from operations will be sufficient to fund ongoing operations and investing activities excluding funding on Project Millennium.

Crude oil prices, and to a lesser degree natural gas prices, are important components in determining Suncor's yearly earnings and cash flow, as well as net debt levels. In 1999, crude oil prices experienced extremes that were unanticipated. The benchmark WTI price dropped to below US\$12 per barrel in early 1999 and reached a high of over US\$26 per barrel in December 1999. While Suncor does not believe that crude oil prices will be sustained at the December 1999 monthly average of over US\$26 per barrel, management believes prices will be higher than the company forecast last year. Suncor's financing and capital spending plans are based upon the following financial assumptions: the yearly average WTI crude oil price will be in the range of US\$17.50 per barrel to US\$18.00 per barrel over the next three years (last year's three-year forecast: US\$13.00 in 1999 to U.S.\$17.50 in 2001); there will be an increase in demand for natural gas, moving prices from \$2.44 per thousand cubic feet in 1999, to approximately \$2.50 to \$3.00 per thousand cubic feet in 2002 (last year's three-year forecast: \$1.95 per thousand cubic feet, moving to approximately \$2.50 per thousand cubic feet in 2002); and the Canadian dollar will strengthen versus the U.S. dollar from the 1999 average of \$0.67, to \$0.70 by 2002.

During the two years ending December 31, 2001, Suncor's debt/cash flow ratio is expected to climb from its current level of 2.3 times to a short-term peak in the 2.5 to 3.0 times range, due to planned growth expenditures. This is unchanged from last year's forecast. Subject to the timely completion, final project cost and successful implementation of Project Millennium and contingent on the company's financial assumptions, management believes that expected increases in cash flow will reduce the debt/cash flow ratio to



Ratio is expected to remain in the 2.5 – 3 times range until the completion of Project Millennium.

Suncor's long-term goal of 1.5 to 2.0 times after the year 2001.

In 1999 a number of financing initiatives were completed to support Suncor's growth initiatives. These included the issuance of preferred securities and the sale of accounts receivable (see notes 13 and 2, respectively, to the financial statements). However, internally generated cash over the next three years is expected to be insufficient to support the increased spending based on the company's current outlook for commodity prices. A financing plan has been developed that management believes will allow Suncor to raise additional capital if necessary. Components of the plan include the following:

- Maintain sufficient debt capacity. Suncor currently has \$525 million of public debt, and credit and term loan facilities of \$1.9 billion, of which \$695 million had been used as at December 31, 1999;
- Manage each business unit with a view to achieving positive net cash flow targets (excluding Project Millennium);
- Examine all growth opportunities with a view to reducing the need for Suncor to invest its own capital through mutually beneficial relationships with third parties;
- Pursue the sale of non-core assets;
- Evaluate further opportunities to hedge commodity prices; and
- Issue equity if required.

This approach to financial management could change in scope, timing and magnitude depending on factors such as commodity prices, production volumes, interest rates, exchange rates, and capital market conditions.

Operating Commitments

When Suncor commenced its Oil Sands operations in northern Alberta over 30 years ago, and until recently, it has had to invest in assets and related services that in more developed geographic areas would be provided by third parties. These include assets such as crude oil and natural gas pipelines, electrical and steam generation facilities, and housing accommodations for contract workers. Suncor believes

organizations with the specific expertise associated with such assets can provide more cost-effective services. As part of the Oil Sands growth initiatives, it will look to exit such businesses and obtain services from third parties. Suncor's long-term transportation service agreement for access to a portion of the Enbridge Athabasca Pipeline and its agreement with TransAlta to have that company build, own and operate a cogeneration facility that will meet a portion of the energy needs of Suncor's Oil Sands operation, are examples of such opportunities. While

these existing arrangements have, and the new arrangements will, result in long-term operating commitments, the company believes this approach has the potential to reduce operating and administrative expenses.

During 1999, Suncor's quarterly dividend was \$0.17 per share, unchanged from 1998. Dividend levels are reviewed quarterly in light of Suncor's growth-related initiatives, financial position, financing requirements, cash flow and other factors considered relevant by the Board of Directors.

Capital and Exploration Investing Expenditures

(\$ millions)	2000 Goal	1999 Actual	1998 Actual
Oil Sands (excluding Project Millennium)			
Sustaining capital	56	28	32
Environmental	4	1	4
Heavy oil	21	—	—
Strategic			
Production improvements	56	118	81
Expansion		6	46
Steepbank	3	13	192
	140	166	355
Project Millennium			
Production enhancement phase	11	85	70
Millennium Phase 2	1 015	806	82
	1 026	891	152
Exploration and Production			
Exploration	52	75	93
Development	77	75	126
Environmental	2	1	2
Finding and development capital	131	151	221
Coal bed methane	5	2	—
Heavy oil	—	40	10
Other	9	7	11
	145	200	242
Sunoco			
Refining and distribution	30	18	25
Retail marketing	24	19	28
Environmental	5	3	6
Other	1	2	1
	60	42	60
Corporate			
Stuart Oil Shale Project	15	50	127
Other	—	1	—
Alternative and renewable energy	20	—	—
Total	1 351	1 350	936

Management's Statement on Financial Reporting

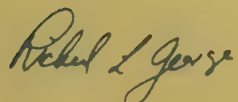
The financial statements on pages 42 to 62 which consolidate the financial results of Suncor Energy Inc., its subsidiaries and joint ventures, and all information in this annual report, are the responsibility of management.

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include some amounts which are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this annual report is consistent with that in the financial statements.

In management's opinion the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized on pages 42 to 44. In meeting its responsibilities for the integrity of the financial statements, management maintains a system of internal controls and an internal audit program. Management also administers a program of proper business conduct compliance.

PricewaterhouseCoopers LLP, the company's independent auditors, have audited the accompanying financial statements. Their report accompanies this statement.

The Audit Committee of the Board of Directors, composed of five independent directors, meets regularly with management, the internal auditors and PricewaterhouseCoopers LLP to review their activities and to discuss auditing, management information systems, internal control, accounting policy and financial reporting matters. The Audit Committee also meets quarterly to review interim financial statements prior to their release. The internal auditors and PricewaterhouseCoopers LLP have unrestricted access to the company, the Audit Committee and the Board of Directors. The Audit Committee reviews the financial statements and Management's Discussion and Analysis and recommends their approval to the Board of Directors.



Richard L. George
President and
Chief Executive Officer
January 20, 2000



Michael W. O'Brien
Chief Financial Officer

Auditors' Report

To the Shareholders of Suncor Energy Inc.

We have audited the consolidated balance sheets of Suncor Energy Inc. as at December 31, 1999, 1998 and 1997 and the consolidated statements of earnings, cash flows and changes in shareholders' equity for each of the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 1999, 1998 and 1997 and the results of its operations and cash flows for each of the years then ended in accordance with accounting principles generally accepted in Canada.



PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
January 20, 2000

Summary of Significant Accounting Policies

Suncor Energy Inc. is an integrated oil and gas company, whose three operating segments are Oil Sands, Exploration and Production and Sunoco.

Oil Sands includes the production of light sweet and light sour crude oil, diesel fuel and various custom blends from oil sands mined in the Athabasca region of northeastern Alberta, and the marketing of these products in Canada and the United States.

Exploration and Production includes the exploration, acquisition, development, production, marketing and transportation of crude oil and natural gas in Canada and the marketing of natural gas in Canada and the United States.

Sunoco includes the manufacture, transportation and marketing of petroleum and petrochemical products, primarily in Ontario and Quebec, and, commencing in 1997, the marketing of natural gas in Ontario. Petrochemical products are also sold in the United States and Europe.

The company is also in the commissioning phase of an oil shale project in Queensland, Australia, which is currently being treated as a Corporate project for segmented reporting purposes. Commercial production from this first phase is expected to commence in 2000, at which time the oil shale operation will be a separate foreign geographic segment.

The significant accounting policies of the company are summarized below:

(a) Principles of consolidation and the preparation of financial statements

These consolidated financial statements are prepared and reported in Canadian dollars in accordance with Canadian generally accepted accounting principles (GAAP), which differ in some respects from GAAP in the United States. The significant differences in GAAP, as applicable to these consolidated financial statements and notes, are described in the company's Form 40-F report, which is filed with the United States Securities and Exchange Commission and is available on request.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of its joint ventures.

The timely preparation of financial statements in conformity with generally accepted accounting principles requires that management make estimates and assumptions, and use judgment, regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

(b) Cash equivalents and investments

The company considers all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist primarily of term deposits and certificates of deposit. Investments with maturities from greater than three months to

one year are classified as short-term investments, while those with maturities in excess of one year are classified as long-term investments. Cash equivalents and short-term investments are stated at cost, which approximates market value.

(c) Revenues

The company deems production from its oil sands plant, excluding diesel sales and synthetic crude oil sales under long-term agreements, as well as its conventional crude oil production to be used first for internal refinery consumption. The company also deems a portion of its natural gas production to be sold to Sunoco for resale to its natural gas customers. Therefore, on consolidation, revenues from these deemed sales are eliminated from sales and other operating revenues and purchases of crude oil and products.

The company also uses a portion of its natural gas production for internal consumption at its oil sands plant and refinery. On consolidation, revenues from these sales are eliminated from sales and other operating revenues and operating, selling and general expenses.

(d) Capital assets

Capital assets are recorded at cost less accumulated provisions for depreciation, depletion and amortization. Capital assets are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated future cash flows.

The company follows the successful efforts method of accounting for its crude oil and natural gas operations. Under the successful efforts method, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration costs, including geological and geophysical costs, are expensed as incurred. Exploratory drilling costs are capitalized initially. If it is determined that the well does not contain proved reserves, the capitalized exploratory drilling costs are charged to expense, as dry hole costs, at that time. The related land costs are expensed through the amortization of unproved properties as covered under the Exploration and Production section of the following policy.

Development costs, which include the costs of wellhead equipment, development drilling costs, gas plants and handling facilities, applicable geological and geophysical costs and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and gas to the surface are expensed.

Costs specifically related to the construction and development of major projects such as the oil sands projects and the Stuart oil shale project are capitalized. Depreciation commences when the facilities are substantially complete and ready for commercial production to begin.

(e) Depreciation, depletion and amortization

Oil Sands

Capital assets are depreciated over their useful lives, except for lease acquisition costs and certain mine assets, which are

depreciated over the life of proved reserves. Depreciation over useful lives is on a straight line basis. Depreciation over the life of proved reserves is on a unit of production basis.

The company is depreciating capital assets as follows:

- (i) mobile equipment over 3 to 15 years;
- (ii) mine equipment and acquisition costs of original operating Leases #86 and #17 over approximately 36 million barrels of proved reserves;
- (iii) plant and other capital assets primarily over 10 to 40 years.

Exploration and Production

Unproved properties whose acquisition costs are individually significant are evaluated for impairment by management. Impairment of unproved properties whose acquisition costs are not individually significant is provided for through amortization of the portion not expected to become producing, based on historical experience, over the average projected holding period.

Acquisition costs of proved properties are depleted using the unit of production method based on proved reserves. Capitalized exploratory drilling costs and development costs are depleted on the basis of proved developed reserves. For purposes of the depletion calculation, production and reserves volumes for oil and natural gas are converted to a common unit of measure on the basis of their approximate relative energy content. Gas plants, support facilities and equipment are depreciated on a straight line basis over their useful lives, which average 13 years.

Sunoco

Depreciation of capital assets is on a straight line basis over their useful lives. The refinery and additions thereto are depreciated over an average of 30 years, service stations and related equipment over an average of 20 years and other facilities and equipment over 3 to 25 years.

(f) Disposals

Gains or losses on disposals of capital assets are generally recognized in earnings. For oil and gas capital assets, gains or losses are recognized in earnings for significant disposals or disposal of an entire property. However, the acquisition cost of an unproved property surrendered or abandoned which is not individually significant or a partial abandonment of a proved property is charged to accumulated depreciation, depletion or amortization, as appropriate.

(g) Deferred charges

Overburden removal costs incurred to expose oil sands and oil shale for mining, including depreciation on overburden removal equipment where applicable, are deferred. These costs are amortized based on the amount of oil sands and oil shale mined in the year, the ratio of total overburden to be removed to total reserves of oil sands and oil shale to be mined and the removal cost, determined on a last-in, first-out (LIFO) basis, per unit of overburden.

The cost of major maintenance shutdowns is deferred and amortized on a straight line basis over the period to the next shutdown which varies from two to seven years. Normal

maintenance and repair costs are charged to expense as incurred.

Oil sands preproduction costs are amortized on a unit of production basis over the life of proved producing reserves.

(h) Reclamation and environmental remediation costs

Reclamation and environmental remediation costs for identified sites are estimated and charged against earnings when there exists a regulatory or statutory requirement or contractual agreement, or when management has made a decision to decommission or restore a site, providing that assessments indicate that such costs are probable and reasonably estimable.

Estimated reclamation costs in the company's upstream operations are accrued on the unit of production basis. Estimated environmental remediation costs, which are predominantly in the company's downstream operation, are accrued for those sites where assessments indicate that such work is required.

Costs are accrued based upon currently known information, estimated timing of remedial actions, and existing requirements and technology. Changes in these factors may result in material changes to estimated costs, which will be recognized prospectively when known.

(i) Employee future benefits

Pension expense

The company has a defined benefit pension plan, under which employees do not make contributions (non-contributory), and a defined contribution pension plan providing retirement benefits for its eligible employees. The company also has supplementary non-contributory defined benefit pension plans providing additional retirement benefits for its executives and senior employees.

Pension expense related to the defined benefit plans includes the current service costs, interest costs and the amortization of adjustments arising from plan amendments, changes in assumptions and experience gains and losses over the expected average remaining service life of the employees. This expense reflects management's estimates of the pension plans' expected investment yield, salary escalation, mortality of members, terminations and the ages at which members will retire. Company contributions to the defined contribution plan are expensed as incurred.

Other post-retirement benefits

The company provides certain health care and life insurance benefits for its retired employees and eligible surviving dependants. Costs of these benefits are charged to earnings as payments are made by the company on behalf of retirees and dependants.

New recommendations on employee future benefits, approved in 1998 by the Accounting Standards Board of the Canadian Institute of Chartered Accountants will be adopted effective January 1, 2000.

(j) Income taxes

By law, some costs and revenues may be deducted from or added to earnings in the calculation of taxable income in years earlier or later than the year that they are actually recorded in the consolidated statements of earnings. The income taxes in the consolidated statements of earnings are based upon the revenues and expenses actually recorded but differ from taxes actually paid or payable. The cumulative effect of these differences is shown in the consolidated balance sheets as "deferred income taxes".

New recommendations issued in 1997 by the Accounting Standards Board of the Canadian Institute of Chartered Accountants will be adopted effective January 1, 2000.

(k) Inventories

Inventories of crude oil and refined products are valued at the lower of cost using the last-in, first-out (LIFO) method and net realizable value.

Materials and supplies are valued at the lower of average cost and net realizable value.

(l) Derivative financial instruments

The company periodically enters into derivative financial instrument contracts such as forwards, futures and swaps to hedge against the potential adverse impact of market prices for its petroleum and natural gas products and to protect its Canadian dollar income and cash flows against adverse foreign currency exchange movements. The company also periodically enters into derivative financial instrument contracts such as interest rate swaps when there is an opportunity to lower the cost of borrowed funds. The company does not use derivative financial instruments involving multipliers or leverage.

Derivative contracts are initiated within the guidelines of the company's risk management policies, which require stringent authorities for approval and commitment of contracts, designation of the contracts by management as hedges of the related transactions, and monitoring of the effectiveness of such contracts in reducing the related risks. Contract maturities are consistent with the settlement dates of the related hedged transactions.

Derivative contracts accounted for as hedges are not recognized in the consolidated balance sheets. Gains or losses on these contracts are recognized in earnings and cash flows when the related sales revenue, interest expense and cash flows are recognized.

Gains or losses resulting from changes in the fair value of derivative contracts not accounted for as hedges are recognized in earnings and cash flows.

(m) Interest capitalization

Interest costs relating to the construction and pre-operating stages of major development projects and to the portion of non-producing oil and gas properties expected to become producing are capitalized as part of the cost of such capital assets.

(n) Foreign currency translation

Monetary assets and liabilities in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. Other assets and related depreciation, depletion and amortization, other liabilities, revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings, except for unrealized exchange gains and losses arising on translation of long-term liabilities with fixed or ascertainable lives. These gains and losses are deferred and amortized over the remaining terms of the liabilities.

The company's oil shale project in Australia is integrated with the company's other activities and is translated in the manner described above.

(o) Stock-based compensation plans

Under the company's Executive Stock Plan and Employee Stock Option Program, common share options are granted to certain executives, senior employees and non-employee directors. The company does not recognize compensation expense on the issuance of common share options under these programs because the exercise price of the share options is equal to the market value of the common shares at the date of grant.

The company has established long-term employee incentive plans which provide awards to certain senior executives and employees based on the market price of the company's common shares and achievement of certain performance measurement criteria relating to the company's business segments. These awards vest on April 1, 2002 and are payable at that time, generally in equal amounts of cash and common shares of the company. The estimated costs of the cash portion of these awards, based on share price and expected performance achievement, are recorded as compensation expense over the vesting period. Changes in the share price, up or down, will change the compensation expense. Such changes will be recognized prospectively when they occur.

The company has also established a directors' compensation plan whereby directors of the company may elect to receive half or all of their annual remuneration as directors in common share equivalents referred to as Deferred Share Units (DSU). The estimated costs of directors' compensation in the form of DSU, based on share price, are recorded as compensation expense annually.

Consolidated Statements of Earnings

for the years ended December 31

(\$ millions)	1999	1998	1997
REVENUES			
Sales and other operating revenues (notes 2 and 4)	2 383	2 068	2 148
Interest	4	2	6
	2 387	2 070	2 154
EXPENSES			
Purchases of crude oil and products	519	366	429
Operating, selling and general (note 10)	750	682	705
Exploration (note 2)	40	40	50
Royalties (note 1)	99	78	80
Taxes other than income taxes (note 2)	334	325	312
Depreciation, depletion and amortization	318	264	234
Gain on disposal of assets	(34)	(6)	(9)
Interest (note 2)	26	24	13
	2 052	1 773	1 814
EARNINGS BEFORE INCOME TAXES	335	297	340
PROVISION FOR INCOME TAXES (note 3)			
Current			
Income taxes on earnings	29	(3)	16
Income tax refund	—	(16)	(11)
	29	(19)	5
Deferred			
Income taxes on earnings	106	123	112
Income tax refund	—	5	—
	106	128	112
	135	109	117
NET EARNINGS	200	188	223
Dividends on preferred securities (note 13)	(22)	—	—
Net earnings attributable to common shareholders	178	188	223
PER COMMON SHARE (dollars) (note 14)			
Net earnings	1.81	1.70	2.04
Dividends on preferred securities	(0.20)	—	—
Net earnings attributable to common shareholders			
	1.61 1.60	1.70 1.70	2.04 2.02
■ Basic ■ Diluted			
Cash Dividends	0.68	0.68	0.68

See accompanying summary of accounting policies and notes.

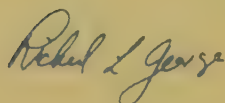
Consolidated Balance Sheets

as at December 31

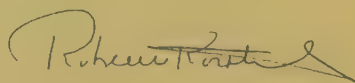
(\$ millions)	1999	1998	1997
ASSETS			
Current assets			
Cash and cash equivalents	5	26	13
Accounts receivable (notes 2 and 4)	291	190	267
Income taxes recoverable	—	10	—
Inventories (note 5)	161	175	159
Total current assets	457	401	439
Capital assets, net (note 6)	4 528	3 504	2 817
Deferred charges and other (note 7)	191	199	201
Total assets	5 176	4 104	3 457
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Short-term borrowings	32	16	36
Accounts payable	277	125	179
Accrued liabilities (notes 10 and 11)	339	169	229
Income taxes	15	—	10
Taxes other than income taxes	46	59	53
Current portion of long-term borrowings (note 8)	1	1	6
Total current liabilities	710	370	513
Long-term borrowings (notes 8 and 9)	1 306	1 298	767
Accrued liabilities and other (note 10)	179	161	166
Deferred income taxes	839	756	610
Commitments and contingencies (note 12)			
Shareholders' equity			
Preferred securities (note 13)	514	—	—
Share capital (note 14)	524	518	513
Retained earnings	1 104	1 001	888
Total shareholders' equity	2 142	1 519	1 401
Total liabilities and shareholders' equity	5 176	4 104	3 457

See accompanying summary of accounting policies and notes.

Approved on behalf of the Board:



R. L. George, Director



R. W. Korthals, Director

Consolidated Statements of Cash Flows

for the years ended December 31

(\$ millions)	1999	1998	1997
OPERATING ACTIVITIES			
Cash flow provided from operations (1), (2)	591	580	575
Decrease (increase) in operating working capital			
Accounts receivable (note 2)	(101)	77	25
Inventories	14	(16)	(12)
Accounts payable and accrued liabilities	322	(114)	(21)
Taxes payable	12	(14)	14
Cash provided from operating activities	838	513	581
CASH USED IN INVESTING ACTIVITIES (2)	(1 290)	(937)	(884)
NET CASH DEFICIENCY BEFORE FINANCING ACTIVITIES	(452)	(424)	(303)
FINANCING ACTIVITIES			
Increase (decrease) in short-term borrowings	16	(20)	12
Issuance of preferred securities (note 13)	507	—	—
Stuart oil shale project borrowings	11	49	22
Issuance of medium term notes	—	—	400
Repayment of commercial paper borrowings (note 13)	(507)	—	—
Repayment of 12% debentures, Series A	—	(55)	(5)
Net increase (decrease) in other long-term borrowings	510	533	(45)
Issuance of common shares under stock option plan (note 14)	6	5	5
Dividends paid on preferred securities (3) (note 13)	(37)	—	—
Dividends paid on common shares	(75)	(75)	(74)
Cash provided from financing activities	431	437	315
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(21)	13	12
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	26	13	1
CASH AND CASH EQUIVALENTS AT END OF YEAR	5	26	13
PER COMMON SHARE (dollars) (note 14)			
(1) Cash flow provided from operations	5.36	5.27	5.24
(3) Dividends paid on preferred securities (pre-tax)	(0.34)	—	—
Cash flow provided from operations after deducting dividends paid on preferred securities	5.02	5.27	5.24
(2) See Schedules of Segmented Data on pages 50 and 51.			

See accompanying summary of accounting policies and notes.

Consolidated Statements of Changes
in Shareholders' Equity

(\$ millions)	Preferred Securities	Share Capital	Retained Earnings
At December 31, 1996	—	508	739
Net earnings	—	—	223
Dividends paid	—	—	(74)
Issued for cash under stock option plan	—	5	—
At December 31, 1997	—	513	888
Net earnings	—	—	188
Dividends paid	—	—	(75)
Issued for cash under stock option plan	—	4	—
Issued under dividend reinvestment plan	—	1	—
At December 31, 1998	—	518	1 001
Net earnings	—	—	200
Dividends paid	—	—	(97)
Issuance of preferred securities (note 13)	514	—	—
Issued for cash under stock option plan	—	6	—
At December 31, 1999	514	524	1 104

See accompanying summary of accounting policies and notes.

Schedules of Segmented Data*

for the years ended December 31

	Oil Sands			Exploration and Production			Sunoco		
(\$ millions)	1999	1998	1997	1999	1998	1997	1999	1998	1997
EARNINGS									
Revenues**									
Sales and other									
operating revenues	461	421	281	143	114	194	1 779	1 533	1 673
Intersegment revenues***	428	347	470	163	176	108	—	—	—
Interest	—	—	—	—	—	—	—	—	—
	889	768	751	306	290	302	1 779	1 533	1 673
Expenses									
Purchases of crude oil and products	6	10	—	—	—	—	1 090	845	988
Operating, selling and general	357	333	334	85	84	87	264	258	269
Exploration	—	—	—	40	40	50	—	—	—
Royalties	51	43	31	48	35	49	—	—	—
Taxes other than income taxes	9	7	8	5	5	4	320	313	300
Depreciation, depletion and amortization	177	128	109	87	84	74	53	51	51
(Gain) loss on disposal of assets	2	(1)	(2)	(36)	(5)	(9)	—	—	2
Interest	—	—	—	—	—	—	—	—	—
	602	520	480	229	243	255	1 727	1 467	1 610
Earnings (loss) before income taxes	287	248	271	77	47	47	52	66	63
Income taxes	(113)	(98)	(92)	(34)	(22)	(23)	(21)	(26)	(24)
Net earnings (loss)	174	150	179	43	25	24	31	40	39
As at December 31									
TOTAL ASSETS	3 178	2 081	1 689	962	943	819	849	874	908
CAPITAL EMPLOYED****	1 371	1 254	543	730	774	658	413	503	500
RETURN ON AVERAGE CAPITAL EMPLOYED (%) ****									
	13.2	16.7	33.0	5.7	3.5	4.0	6.8	7.9	7.9

* The company currently has no foreign geographic segments. See note 2 for information on export sales. Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

** One customer in the Oil Sands segment in 1999 represented 10% or more of the company's 1999 consolidated revenues. There were none in 1998 and 1997.

*** Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

**** Capital Employed – the total of shareholders' equity and debt (short-term borrowings and current and long-term portions of long-term borrowings), less capitalized costs related to major projects in progress. Long-term borrowings are recorded mainly in the Corporate segment.

See accompanying summary of accounting policies and notes.

(\$ millions)	Corporate and Eliminations			Total		
	1999	1998	1997	1999	1998	1997
EARNINGS						
Revenues**						
Sales and other						
operating revenues	—	—	—	2 383	2 068	2 148
Intersegment revenues***	(591)	(523)	(578)	—	—	—
Interest	4	2	6	4	2	6
	(587)	(521)	(572)	2 387	2 070	2 154
Expenses						
Purchases of crude oil and products	(577)	(489)	(559)	519	366	429
Operating, selling and general	44	7	15	750	682	705
Exploration	—	—	—	40	40	50
Royalties	—	—	—	99	78	80
Taxes other than income taxes	—	—	—	334	325	312
Depreciation, depletion and amortization	1	1	—	318	264	234
(Gain) loss on disposal of assets	—	—	—	(34)	(6)	(9)
Interest	26	24	13	26	24	13
	(506)	(457)	(531)	2 052	1 773	1 814
Earnings (loss) before income taxes	(81)	(64)	(41)	335	297	340
Income taxes	33	37	22	(135)	(109)	(117)
Net earnings (loss)	(48)	(27)	(19)	200	188	223
As at December 31						
TOTAL ASSETS	187	206	41	5 176	4 104	3 457
CAPITAL EMPLOYED****	(117)	(70)	(90)	2 397	2 461	1 611
RETURN ON AVERAGE CAPITAL EMPLOYED (%) ****						
				8.8	9.9	14.8

Schedules of Segmented Data*

for the years ended December 31

	Oil Sands			Exploration and Production			Sunoco		
(\$ millions)	1999	1998	1997	1999	1998	1997	1999	1998	1997
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash provided from (used in) operating activities:									
Cash flow provided from (used in) operations									
Net earnings (loss)	174	150	179	43	25	24	31	40	39
Exploration expenses									
Cash	—	—	—	12	16	25	—	—	—
Dry hole costs	—	—	—	28	24	25	—	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	177	128	109	87	84	74	53	51	51
Deferred income taxes	107	79	85	32	15	10	(31)	15	5
Current income tax provision allocated to Corporate	6	19	7	2	7	13	52	11	19
(Gain) loss on disposal of assets	2	(1)	(2)	(36)	(5)	(9)	—	—	2
Other	(12)	(12)	(9)	3	1	—	(3)	(4)	(5)
Overburden removal outlays	(53)	(46)	(34)	—	—	—	—	—	—
Increase (decrease) in deferred credits and other	4	3	(4)	1	—	—	1	(1)	10
Total cash flow provided from (used in) operations	405	320	331	172	167	162	103	112	121
Decrease (increase) in operating working capital	83	(8)	33	27	(13)	(2)	69	7	(36)
Total cash provided from (used in) operating activities	488	312	364	199	154	160	172	119	85
Cash used in investing activities:									
Capital and exploration expenditures	(1 057)	(507)	(491)	(200)	(242)	(240)	(42)	(60)	(54)
Deferred maintenance shutdown expenditures	(22)	(7)	(36)	—	(1)	1	—	(2)	—
Deferred outlays and other investments	(7)	(1)	(6)	—	1	—	(2)	(3)	(1)
Proceeds from disposals	1	1	2	90	9	13	1	1	—
Total cash used in investing activities	(1 085)	(514)	(531)	(110)	(233)	(226)	(43)	(64)	(55)
Net cash surplus (deficiency) before financing activities	(597)	(202)	(167)	89	(79)	(66)	129	55	30

* The company currently has no foreign geographic segments. See note 2 for information on export sales.
Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.
See accompanying summary of accounting policies and notes.

(\$ millions)	Corporate and Eliminations			Total		
	1999	1998	1997	1999	1998	1997
CASH FLOW BEFORE FINANCING ACTIVITIES						
Cash provided from (used in) operating activities:						
Cash flow provided from (used in) operations						
Net earnings (loss)	(48)	(27)	(19)	200	188	223
Exploration expenses						
Cash	—	—	—	12	16	25
Dry hole costs	—	—	—	28	24	25
Non-cash items included in earnings						
Depreciation, depletion and amortization	1	1	—	318	264	234
Deferred income taxes	(2)	19	12	106	128	112
Current income tax provision allocated to Corporate	(60)	(37)	(39)	—	—	—
(Gain) loss on disposal of assets	—	—	—	(34)	(6)	(9)
Other	1	2	2	(11)	(13)	(12)
Overburden removal outlays	—	—	—	(53)	(46)	(34)
Increase (decrease) in deferred credits and other	19	23	5	25	25	11
Total cash flow provided from (used in) operations	(89)	(19)	(39)	591	580	575
Decrease (increase) in operating working capital	68	(53)	11	247	(67)	6
Total cash provided from (used in) operating activities	(21)	(72)	(28)	838	513	581
Cash used in investing activities:						
Capital and exploration expenditures	(51)	(127)	(62)	(1 350)	(936)	(847)
Deferred maintenance shutdown expenditures	—	—	—	(22)	(10)	(35)
Deferred outlays and other investments	(1)	1	(10)	(10)	(2)	(17)
Proceeds from disposals	—	—	—	92	11	15
Total cash used in investing activities	(52)	(126)	(72)	(1 290)	(937)	(884)
Net cash surplus (deficiency) before financing activities	(73)	(198)	(100)	(452)	(424)	(303)

Notes to the Consolidated Financial Statements

1. ROYALTIES

Alberta Crown royalties totalling \$7 million (1998 – \$5 million; 1997 – \$9 million) were paid in kind, and are not shown in the company's revenues and expenses.

(\$ millions)	1999			1998			1997*		
	Crown	Other	Total	Crown	Other	Total	Crown	Other	Total
■ Oil Sands	48	3	51	35	8	43	8	23	31
■ Exploration & Production	40	8	48	28	7	35	41	8	49
Total	88	11	99	63	15	78	49	31	80

* Lower 1997 Oil Sands Crown royalties reflect the realization of an environmental royalty credit from the Government of Alberta in the amount of \$31 million. The program for claiming this credit ended at the end of 1997.

2. SUPPLEMENTAL INFORMATION

(\$ millions)	1999	1998	1997
Export sales (1)	233	231	292
Exploration expenses			
Geological and geophysical	10	14	23
Other	2	2	2
Cash costs	12	16	25
Dry hole costs	28	24	25
Cash and dry hole costs (2)	40	40	50
Leasehold impairment (3)	12	10	7
	52	50	57
Taxes other than income taxes			
Excise taxes (4)	311	305	292
Production, property and other taxes	23	20	20
	334	325	312
Interest expense			
Long-term interest cost	71	67	38
Less interest capitalized	(45)	(43)	(25)
	26	24	13
Cash interest payments	63	64	28
Allowance for doubtful accounts	3	3	3

During 1999, the company put in place a securitization program to sell, on an ongoing basis, up to \$83 million of accounts receivable, on a limited recourse basis, to a third party. As at December 31, 1999, \$83 million in accounts receivable had been sold under the program.

On December 31, 1998, the company sold, on a limited recourse basis, approximately \$50 million in accounts receivable to third parties.

The company's potential exposure to credit loss under the recourse provisions is not material.

(1) Sales of mainly petrochemicals, natural gas and diesel to customers in the United States and petrochemicals in Europe.

(2) Exploration expenses in the Consolidated Statements of Earnings.

(3) Included in depreciation, depletion and amortization in the Consolidated Statements of Earnings.

(4) Excise taxes are also included in sales and other operating revenues in the Consolidated Statements of Earnings.

3. INCOME TAXES

The provision for income taxes reflects an effective tax rate which differs from the statutory tax rate. A reconciliation of the two rates and the dollar effect is as follows:

(\$ millions)	1999		1998		1997	
	Amount	%	Amount	%	Amount	%
Federal tax rate	127	38	113	38	130	38
Provincial abatement	(34)	(10)	(30)	(10)	(34)	(10)
Federal surtax	4	1	3	1	4	1
Provincial tax rates	52	16	48	16	53	16
Statutory tax and rate	149	45	134	45	153	45
Add (deduct) the tax effect of:						
Crown royalties (see note 1)	44	13	31	11	27	8
Resource allowance	(56)	(17)	(49)	(16)	(54)	(16)
Large corporations tax	10	3	9	3	5	1
Income tax refund*	—	—	(11)	(4)	(11)	(3)
Other	(12)	(4)	(5)	(2)	(3)	(1)
Income taxes and effective rate	135	40	109	37	117	34

1999 income tax payments totalled \$5 million (1998 – net refund of \$19 million; 1997 – net refund of \$10 million).

* During 1998, settlements were reached with Canada Customs and Revenue Agency (formerly Revenue Canada) on a number of taxation issues resulting in refunds totalling \$34 million, \$11 million of which were reflected in 1997 net earnings (\$0.10 per common share). The impact of the refund in 1998 is to increase net earnings by \$11 million (\$0.10 per common share) reflecting a reduction of prior years income taxes of \$5 million and taxable interest of \$6 million (after a provision for income taxes of \$5 million).

4. RELATED PARTY TRANSACTIONS

The following table summarizes the company's related party transactions for the year and balances at the end of the year. These transactions are in the normal course of operations and have been carried out on the same terms as would apply with unrelated parties.

(\$ millions)	1999	1998	1997
Revenues			
Sales to Sunoco joint ventures:			
Refined products	395	309	353
Petrochemicals	108	85	90
At the end of the year, amounts due from related parties are as follows:			
Sunoco joint ventures	45	41	49

Sales to and balances with Sunoco joint ventures are exchange amounts established and agreed to by the related parties, before application of the proportionate consolidation method of accounting.

The company has exclusive supply agreements with two Sunoco joint ventures for the sale of refined products. One agreement expires in 2002, after which the company will continue to be the exclusive supplier of refined products as long as it remains a shareholder. The company plans to maintain its relationship with this joint venture. The other agreement expires in 2003 and will be

automatically renewed thereafter for one year terms until terminated upon twelve months prior written notice. No notice has been given by either party.

The company also has a non-exclusive supply agreement with a Sunoco joint venture for the sale of petrochemicals. The agreement is automatically renewed on an annual basis until it is terminated by either party upon twelve months written notice. No notice has been given by either party.

5. INVENTORIES

(\$ millions)	1999	1998	1997
■ Crude oil	47	58	63
■ Refined products	67	62	54
■ Materials and supplies	47	55	42
Total	161	175	159

The replacement cost at December 31, 1999 of all inventories valued at LIFO exceeded their carrying value by \$37 million (1998 – nil; 1997 – \$7 million).

6. CAPITAL ASSETS

(\$ millions)	1999		1998		1997	
	Cost	Accumulated Provision	Cost	Accumulated Provision	Cost	Accumulated Provision
Oil Sands						
Plant	1 598	485	1 461	449	1 106	410
Mine and mobile equipment	850	243	828	191	330	158
Plant expansion*	—	—	—	—	267	—
Steepbank Mine*	—	—	—	—	238	—
Project Millennium**						
Production enhancement phase	172	2	87	—	17	—
Millennium expansion	905	—	99	—	16	—
	3 525	730	2 475	640	1 974	568
Exploration and Production						
Proved properties	1 190	487	1 242	506	1 093	450
Unproved properties	344	171	288	169	263	166
Pipeline	22	18	22	18	21	17
Other support facilities and equipment	19	12	18	10	15	9
	1 575	688	1 570	703	1 392	642
Sunoco						
Refinery	740	350	724	327	701	304
Marketing and transportation	380	165	362	148	337	137
	1 120	515	1 086	475	1 038	441
Corporate						
Stuart oil shale project**	237	—	187	—	61	—
Other	7	3	6	2	5	2
	244	3	193	2	66	2
	6 464	1 936	5 324	1 820	4 470	1 653
Net capital assets		4 528		3 504		2 817

Interest capitalized during 1999 totalled \$45 million (1998 – \$43 million; 1997 – \$25 million).

* During the fourth quarter of 1998, plant expansion and Steepbank Mine assets were put into service. At that time, costs associated with these projects were transferred to Plant assets and Mine and mobile equipment, and depreciation of these costs commenced.

** The depreciation and depletion of costs related to these major projects will begin when the facilities are substantially complete and ready for commercial production to begin.

7. DEFERRED CHARGES AND OTHER

(\$ millions)	1999	1998	1997
Oil sands overburden removal costs (see below)	85	95	86
Oil sands preproduction costs	8	9	11
Deferred maintenance shutdown costs	45	44	52
Investments*	8	8	8
Goodwill**	13	14	14
Other	32	29	30
	191	199	201
Oil sands overburden removal costs			
Balance – beginning of year	95	86	80
Outlays during year	53	46	34
Depreciation on equipment during year	6	2	3
	154	134	117
Amortization during year	(69)	(39)	(31)
Balance – end of year	85	95	86

* Includes investments in partly paid Restricted Class Shares of the Australian joint venture participants in the Stuart oil shale project, Central Pacific Minerals NL (CPM) and Southern Pacific Petroleum NL (SPP), in 1997 totalling \$4 million. These investments are accounted for on the cost basis. They convey to the company a right, but not an obligation, to fully pay for 18 850 000 and 57 000 000 Restricted Class Shares of CPM and SPP, respectively, for an additional investment of approximately \$64 million. This amount may change in the future as foreign exchange rates change. The balance owing is payable within six months of the project becoming fully operational. If Suncor does not pay the balance owing, its Restricted Class Shares would be forfeited and the investment of \$4 million charged to expense. Ownership of these shares would represent approximately a 14% interest in CPM and SPP as at December 31, 1999. The Restricted Class Shares would automatically convert into an equal number of common shares in June 2004, or earlier in certain circumstances.

The market value of these common shares at December 31, 1999, based on quoted market prices, was approximately \$222 million (1998 – \$157 million; 1997 – \$245 million). It is uncertain, however, whether the quoted market prices would be fully realized upon any future sale of these shares.

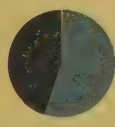
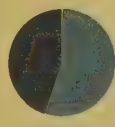
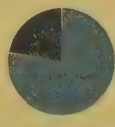
** The company's proportionate share of goodwill of its Sunoco joint ventures is being amortized to earnings on a straight line basis over 40 years, subject to annual review for impairment.

8. LONG-TERM BORROWINGS

(\$ millions)	1999	1998	1997
Fixed rate borrowings			
Medium Term Notes, maturing in 2007. Interest payable semi-annually*	400	400	400
7.4% Debentures, Series C, maturing in 2004. Redeemable at any time, at the company's option**	125	125	125
Borrowings under or with support of lines of credit converted to fixed rate obligations by interest rate swap transactions, maturing in 2003. Interest payable quarterly at rates averaging 5.6%***	110	110	—
12% Debentures, Series A, maturing in 2003. Repayable at the rate of \$5 million annually, redeemable at any time, at the company's option****	—	—	55
Stuart oil shale project borrowings with interest at 7.75%. Australian \$87 million. Principal and interest repayable from project net cash flows (note 12 (b))	82	71	22
Sunoco joint venture borrowings with interest at rates averaging 7.6% at December 31, 1999 (1998 – 7.1%; 1997 – 7.2%)	5	5	6
	722	711	608
Less current portion of fixed rate long-term borrowings	1	1	6
	721	710	602
Variable rate borrowings*****			
Borrowings with interest at variable rates averaging 5.2% at December 31, 1999 (1998 – 5.3%; 1997 – 4.3%) under or with support of lines of credit	585	588	165
Total long-term borrowings	1 306	1 298	767

- * During 1997, the company issued \$400 million of medium term notes, \$250 million in the first quarter at an interest rate of 6.8%, and \$150 million in the third quarter at an interest rate of 6.1%. The money received was used to repay short-term promissory notes and borrowings under the company's lines of credit.
- ** During 1996, the company entered into a cross-currency interest rate swap transaction to convert its 7.4% Debentures to a 6.2% fixed interest rate U.S. dollar obligation of approximately \$91 million. Also in 1996, the company entered into another cross-currency interest rate swap transaction to convert the U.S. \$91 million obligation back to a fixed rate Canadian \$125 million obligation. Both contracts will remain in place for the term of the debenture. The net effect of the two swap transactions is to reduce the effective interest rate on the debentures from 7.3% (7.4% coupon rate) to 5.5%. The principal obligation remains unchanged.
- *** During 1998, the company entered into interest rate swap transactions to convert \$50 million and \$60 million of variable rate borrowings to fixed interest rate obligations at 5.5% and 5.7%, respectively.
- **** During 1998, the company exercised its option to redeem the remaining \$50 million of 12% Debentures, Series A outstanding after a \$5 million sinking fund redemption on the same date. The purpose of the early redemption was to replace the debenture with lower interest rate financing.
- ***** During 1999, the company entered into a cross-currency interest rate swap transaction to convert U.S. \$183 million of variable rate borrowings with interest based on 90 day LIBOR to Canadian \$278 million with interest based on 90 day bankers acceptances.

Long-term borrowing

(percentages)	1999	1998	1997
			
■ Variable rate	45	45	22
■ Fixed rate	55	55	78

Principal repayments of long-term borrowings in each of the next five years are as follows:

(\$ millions)	
2000	6
2001	4
2002	4
2003	374
2004	458

Principal repayments for the period 2000 to 2004 include \$22 million of Stuart oil shale project borrowings estimated to be repayable from project net cash flows. Actual amounts repayable and the timing of repayments could differ from those estimates.

9. LINES OF CREDIT

At December 31, 1999, the company had available \$1 926 million in credit and term loan facilities, of which \$328 million had been drawn, as follows:

- A facility for \$600 million which is fully revolving for 364 days, has a term period of three years and expires in 2003.
- A facility for U.S. \$183 million (Cdn \$278 million) which is non-revolving, has been fully drawn and expires in 2004.
- A facility for \$1 018 million which is fully revolving for six years and expires in 2004.
- Uncommitted facilities totalling \$30 million, which can be terminated at any time at the option of the lenders.

The company is also authorized, supported by unutilized credit and term loan facilities, to issue commercial paper to a maximum of \$600 million having a term not to exceed 364 days. At December 31, 1999, the company had \$367 million in commercial paper outstanding.

These credit facilities are subject to commitment fees, the amounts of which are not material.

10. ACCRUED LIABILITIES AND OTHER

(\$ millions)	1999	1998	1997
■ Reclamation & environmental remediation costs (a)	86	87	90
■ Pension costs (see note 12)	39	50	61
■ Other (b)	54	24	15
Total	179	161	166

(a) Reclamation and environmental remediation costs

Total accrued reclamation and environmental remediation costs also include \$13 million in current liabilities (1998 – \$14 million; 1997 – \$13 million). Payments during 1999 totalled \$13 million (1998 – \$11 million; 1997 – \$18 million).

The estimate of remaining reclamation costs for the company's oil sands operation is \$525 million for its current mining operation and its Project Millennium. \$79 million has been accrued at December 31, 1999. The remaining \$446 million will be accrued over future years on a unit of production basis. Factors such as inflation and changes in technology and proved reserves may materially change the cost estimate.

The exploration and production segment's reclamation and environmental remediation cost estimate decreased in 1999 from \$64 million to \$57 million, reflecting the divestment of non-strategic properties. \$27 million has been accrued to December 31, 1999. The remaining \$30 million will be accrued over future years on a unit of production basis.

(b) Employee incentive plans

In 1997, the company established the following long-term employee incentive plans.

The Special Performance Incentive Plan (SPIP) provides awards of Special Performance Units (SPU) for senior executives of the company. These awards, granted on April 1, 1997, will vest on April 1, 2002. The number of SPU that will vest at that date is based on the value at April 1, 2002, assuming reinvestment of dividends, of a notional \$100 investment in common shares of the company at the grant date. A maximum of 790,000 SPU will vest if the value of the notional investment doubles to \$200. No SPU will vest if the value of the notional investment is \$150 or lower. Vested SPU entitle the holder to receive either an equivalent number of common shares of the company, half the value of which will be paid in cash and the other half in common shares purchased by the company in the open market, or an equivalent number of Deferred Share Units (DSU), which are equal in value to SPU. Of the 790,000 DSU available, executives have elected to receive 721,500. These executives will be required to hold DSU as long as they remain with the company, and will receive additional DSU equivalent in value to future notional dividend reinvestments. Upon the retirement, death or employment termination of the holder, DSU will be paid in cash, based on the value at that time of an equivalent number of common shares of the company.

The Incremental Value Payout Program (IVPP) component of the Employee Long-Term Incentive Plan (ELTIP) provides incentive awards, payable on April 1, 2002, mainly to those employees of the company who are not eligible for SPIP or the Employee Stock Option Program component of the ELTIP (see note 14(b)). One half of the award is based on the average market price of the company's common shares during the twelve weeks prior to April 1, 2002. The other half of the award is based on achievement of certain performance measurement criteria relating to the company's business segments. No award is payable if the market price of the company's common shares is lower than \$54. The awards will be paid in equal amounts of cash and common shares of the company.

In 2001, projected cash awards will reduce cash flow provided from operations as long-term liabilities are transferred to current liabilities in anticipation of cash payments in 2002. At December 31, 1999, 790,000 SPU were earned under the SPIP. The resulting 1999 impact was a charge to expense of \$21 million (1998 – \$4 million; 1997 – \$2 million), and a decrease in net earnings of \$13 million or \$0.12 per common share (1998 – \$3 million or \$0.03 per common share; 1997 – \$1 million or \$0.01 per common share). The 1999 impact of the IVPP was a charge to expense of \$5 million and a decrease in net earnings of \$3 million or \$0.03 per common share (1998 and 1997 – nil).

(c) Directors' compensation plan

In 1999, the company established the Directors' Deferred Share Unit Plan. Under this plan, non-employee directors of the company may elect annually to receive their compensation as

directors for that year in cash, in equal amounts of cash and Deferred Share Units (DSU), or entirely in DSU. The value of one DSU is the market value of one common share of the company. DSU are payable in cash upon the retirement as director or death of the holder. The 1999 impact of this plan on net earnings was not material.

11. PENSION COSTS AND OBLIGATIONS

The company's pension plans include defined benefit plans under which employees do not make contributions, and which provide a pension benefit at retirement based upon years of service and final average earnings.

The company also has a defined contribution plan, under which both the company and employees make contributions. Company contributions are based on employees' earnings and contributions.

Defined Benefit Pension Plans

These pension plans consist of a funded plan which covers most employees, and unfunded supplementary benefit plans which primarily provide supplemental retirement benefits to executives and senior employees. Under the funded plan, the company makes contributions to an independent trustee to cover pension payment obligations to retired employees. The trustee acts as the depository for contributions, the disbursing agent and custodian of the pension plan's assets. These assets are managed by a pension fund investment committee, on behalf of the beneficiaries, which retains independent investment managers and advisors. Pension plan assets are not the company's assets and therefore are not included in the consolidated balance sheets.

Company contributions to the funded pension plan as well as the present value of pension benefit obligations and current period pension expense are determined by an independent actuary based on the following actuarial assumptions and management's estimates, and in accordance with regulatory requirements.

Assumptions and estimates

(percentage)	1999	1998	1997
■ Discount rate	7.25	8.0	8.0
■ Long-term rate of return on plan assets	7.25	8.0	8.0
■ Rate of compensation increase	4.25	4.5	4.5

The following funded status table identifies the present value of the net unfunded obligation, which is the amount by which pension plan obligations exceed the market value of plan assets available to satisfy these obligations at December 31:

(\$ millions)	1999	1998	1997
Pension benefit obligations:			
Funded plan	308	259	247
Unfunded supplementary plans	51	44	40
Total obligations	359	303	287
Less market value of plan assets*	316	278	250
Net unfunded obligation	43	25	37

* Assets in the company's pension plan consist of marketable equity securities, government and corporate bonds and short-term notes.

The above net unfunded obligation is reflected as a liability in the company's balance sheet before recognition of the unamortized asset determined at January 1, 1987, the transition date, and other unamortized plan gains and losses, which represent annually calculated differences between actual and projected plan performance. These actuarial charges/credits to earnings, which are already reflected in the net unfunded obligation, are recorded over the expected average remaining service life of employees, which is currently 13 years (1998 and 1997 – 13 years).

(\$ millions)	1999	1998	1997
Pension liability*	47	58	69
Unamortized transitional asset	(13)	(20)	(26)
Unamortized net (gain) loss	9	(13)	(6)
Net unfunded obligation	43	25	37
* Current portion	8	8	8
Long-term portion	39	50	61
	47	58	69
Company contributions to funded plan	15	14	13

Pension expense

(\$ millions)	1999	1998	1997
■ Defined benefit plan	5	5	6
■ Defined contribution plan	4	3	3
Total	9	8	9

12. COMMITMENTS AND CONTINGENCIES

(a) Operating commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company enters into non-cancellable operating leases for service stations, office space and other property and equipment, as well as transportation service agreements for pipeline capacity and an energy services agreement. Under contracts existing at December 31, 1999, future minimum amounts payable under these leases and agreements are as follows:

(\$ millions)	Pipeline capacity and energy services*	Operating leases
2000	64	33
2001	97	29
2002	111	24
2003	112	20
2004	112	17
Later years	3 274	91
	3 770	214

* Includes annual tolls payable under a transportation service agreement with a major pipeline company to use a portion of its pipeline capacity and tankage for the shipment, commencing in 1999 and extending to 2028, of crude oil from Fort McMurray to Hardisty, Alberta. As the initial shipper on the pipeline, Suncor's annual tolls payable under the agreement could be subject to annual adjustments.

A major energy company is in the process of building a cogeneration facility at the oil sands site with expected completion during the first quarter of 2001. Under long-term energy agreements, Suncor has a commitment to obtain a portion of the power and all of the steam generated by this facility to meet the energy needs of its oil sands operation. Effective October 1999, this company also commenced managing the operations of Suncor's existing energy services facility.

(b) Capital expenditure commitments and contingencies

The success of the Stuart oil shale project is subject to uncertainty because of the developmental nature of the project and the inherent risks associated with the use of the new technology. If the project is unsuccessful, capitalized costs, including capitalized interest, investments in Central Pacific Minerals NL and Southern Pacific Petroleum NL (see note 7), and the project financing liability would be written off. The impact on future earnings, should this occur, is currently estimated to be \$55 million to \$65 million.

At December 31, 1999, the company had outstanding commitments of \$402 million for capital expenditures on Project Millennium.

(c) Uncertainty due to the Year 2000 Issue

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000, and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failures which could affect the company's ability to conduct normal business operations. It is not possible to be certain that all aspects of the Year 2000 Issue affecting the company, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

(d) Contingencies

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated reclamation and environmental remediation costs. These costs are accrued at the company's exploration and production and oil sands operations on the unit of production basis. Estimated environmental remediation costs at service stations are also accrued upon completion of site investigations. These costs are reduced by any estimated gains likely to be realized on a sale of these sites. Any changes in these estimates will affect future earnings.

Under the company's business interruption insurance coverage, the company would bear the first \$70 million of any loss arising from a future insured incident at its oil sands operations.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded mainly from the company's cash provided from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any one quarter or year. The company believes that any liabilities which might arise pertaining to such matters would not be expected to have a material effect on the company's consolidated financial position.

13. PREFERRED SECURITIES

During 1999, the company completed a Canadian offering of \$276 million of 9.05% preferred securities and a U.S. offering of U.S. \$162.5 million of 9.125% preferred securities, the proceeds of which totalled Canadian \$507 million after issue costs of \$17 million (\$10 million after income tax credits of \$7 million). The preferred securities are unsecured junior subordinated debentures, due in 2048 and redeemable at the company's option on or after March 15, 2004. Subject to certain conditions, the company has the right to defer payment of interest on the securities for up to 20 consecutive quarterly periods. Deferred interest and principal amounts are payable in cash, or, at the option of the company, from the proceeds on the sale of equity securities of the company delivered to the trustee of the preferred securities. Accordingly, the preferred securities are classified as share capital in the consolidated balance sheet and the interest distributions thereon, net of income taxes, are classified as dividends. Proceeds from the offerings were used to repay commercial paper borrowings.

14. SHARE CAPITAL**(a) Authorized:****Common shares**

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred shares

The company is authorized to issue an unlimited number of preferred shares without nominal or par value in series.

(b) Issued:

The number of common shares and common share options outstanding, common share prices and per share calculations, for both current and prior periods, reflect a two-for-one split of the company's common shares during 1997.

(\$ millions)	Common Shares	
	Number	Amount
Balance as at December 31, 1996	109 573 672	508
Issued for cash under stock option plan	326 138	5
Issued under dividend reinvestment plan	6 823	—
Balance as at December 31, 1997	109 906 633	513
Issued for cash under stock option plan	297 465	4
Issued under dividend reinvestment plan	12 730	1
Balance as at December 31, 1998	110 216 828	518
Issued for cash under stock option plan	293 925	6
Issued under dividend reinvestment plan	5 366	—
Balance as at December 31, 1999	110 516 119	524

Common Share Options**(i) Executive Stock Plan**

Under this plan, the company has granted common share options to non-employee directors and certain executives of the company and its subsidiaries. The exercise price of an option is equal to the market value of the common shares at the date of grant. Options granted to non-employee directors are exercisable immediately. Options granted to employees are exercisable as follows: one-third after one year, the second third after two years and the final third after three years of the grant date. No option may be exercisable more than 10 years after the grant date.

(ii) Employee Stock Option Program

Under this component of the ELTIP, the company granted 621 110 common share options to certain executives and senior employees. The exercise price for these grants was equal to or greater than the market value of the common shares at the grant date. Options are exercisable on April 1, 2002, one half on a time basis and the other half based on achievement of certain performance measurement criteria.

The following tables cover common share options granted by the company:

(dollars)	Number	Exercise price per share	
		Range	Weighted Average
Outstanding, December 31, 1996	1 778 468	9.50-25.60	17.03
Granted	1 181 570	31.07-52.15	41.72
Exercised	(326 138)	9.50-21.09	13.77
Cancelled	(35 609)	16.44-31.07	25.64
Outstanding, December 31, 1997	2 598 291	9.50-52.15	28.54
Granted	446 518	49.10-52.75	49.31
Exercised	(297 489)	9.50-31.38	14.50
Cancelled	(48 701)	21.09-52.15	42.76
Outstanding, December 31, 1998	2 698 619	9.50-52.75	33.27
Granted	545 228	40.50-60.35	41.39
Exercised	(291 520)	9.50-49.10	19.51
Cancelled	(23 334)	31.07-52.15	51.45
Outstanding, December 31, 1999	2 928 993	9.50-60.35	36.01
Exercisable, December 31			
1997	923 543	9.50-31.38	16.58
1998	1 133 437	9.50-52.15	20.88
1999	1 304 908	9.50-53.95	25.78

Available for Grant, December 31

(number of common shares)	1999	1998	1997
	3 538 234	4 060 129	4 457 945

The following table is an analysis of outstanding and exercisable common share options as at December 31, 1999:

Exercise Price	OUTSTANDING			EXERCISABLE	
	Number	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price Per Share	Number	Weighted Average Exercise Price Per Share
\$ 9.50 – \$10.79	45 678	3	9.89	45 678	9.89
\$15.18 – \$15.66	85 510	4	15.61	85 510	15.61
\$16.44 – \$20.88	298 791	5	16.83	298 791	16.83
\$21.09 – \$25.60	458 616	6	22.11	358 616	21.13
\$31.07 – \$31.38	512 098	7	31.09	344 761	31.10
\$40.50 – \$60.35	1 528 300	8	47.50	171 552	49.71
TOTAL	2 928 993	7	36.01	1 304 908	25.78

(iii) Fair value of options granted

The weighted average fair value of common share options granted in 1999 is \$14.01 per share (1998 – \$18.09 per share; 1997 – \$11.33 per share). The fair value of common share options granted is estimated as at the grant date using the Black-Scholes option-pricing model, using the following assumptions:

	1999	1998	1997
Dividend	\$0.68/ share	\$0.68/ share	\$0.68/ share
Risk-free interest rate	4.89%	5.31%	5.69%
Expected life	7 years	7 years	7 years
Expected volatility	32%	32%	20%

15. FINANCIAL INSTRUMENTS

(a) Balance sheet financial instruments

The company's financial instruments recognized in the consolidated balance sheets consist of cash and cash equivalents, accounts receivable, investments in CPM and SPP, substantially all current liabilities and long-term borrowings.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The fair values of cash and cash equivalents, accounts receivable and current liabilities approximate their carrying amounts due to the short-term maturity of these instruments.

The fair value of the company's investment in the shares of CPM and SPP is not determinable. Information about the terms, conditions and characteristics of these investments is presented in note 7.

The following table summarizes estimated fair value information about the company's long-term borrowings at December 31:

(\$ millions)	1999		1998		1997	
	Carrying amount	Fair value	Carrying amount	Fair value	Carrying amount	Fair value
Long-term borrowings						
– fixed rate	525	516	525	548	575	595
– variable rate	695	695	698	698	165	165
– Sunoco joint ventures	4	4	4	4	5	5
– Stuart oil shale project	82	82	71	71	22	22

The fair value of the company's fixed rate long-term borrowings, which are publicly traded, is based on quoted market prices. The fair value of the company's variable-rate long-term borrowings, proportionate share of the long-term borrowings of its Sunoco joint ventures, and the Stuart oil shale project borrowings approximates the carrying amount.

(b) Derivative financial instruments

The company is also a party to certain derivative financial instruments which are not recognized in the consolidated balance sheets, as follows:

Revenue hedges

The company enters into crude oil, natural gas and foreign currency swap contracts to protect its future Canadian dollar earnings and cash flows from the potential adverse impact of low petroleum and natural gas prices and an unfavourable U.S./Canadian dollar exchange rate. The swap contracts reduce fluctuations in sales revenues by locking in fixed prices and exchange rates on the portion of its sales covered by the contracts. While the swap contracts reduce the risk of exposure to adverse changes in commodity prices and exchange rates, they also reduce the potential benefit of favourable changes in commodity prices and exchange rates.

The swap contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts (payments) by the company for the difference between the contract and market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts (payments)

offset corresponding decreases (increases) in the company's sales revenues. For accounting purposes, amounts received (paid) on settlement are recorded as part of the related hedged sales transactions.

Contracts outstanding at December 31 were as follows:

Contract Amounts

(\$ millions except for average price)	Quantity	Average price* \$ Canadian	Revenue hedged \$ Canadian	Hedge period
As at December 31, 1999				
Crude oil swaps*	52 655 bbl/day	26	503	2000
	9 845 bbl/day	19(a)	67(a)	2000
	35 000 bbl/day	26	327	2001
	4 000 bbl/day	26	38	2002
U.S. dollar swaps	U.S.\$81	1.41	114	2001
	U.S.\$289	1.41	408	2002
As at December 31, 1998				
Crude oil swaps*	23 700 bbl/day	28	242	1999
	6 000 bbl/day	28	61	2000
Natural gas swaps*	2 mmcf/day	2.75	2	1999
U.S. dollar swaps	U.S.\$115	1.39	160	1999
	U.S.\$274	1.39	381	2000
	U.S.\$312	1.41	440	2001
	U.S.\$314	1.42	446	2002
As at December 31, 1997				
Crude oil swaps*	31 500 bbl/day	28	325	1998
	23 700 bbl/day	28	241	1999
	6 000 bbl/day	28	60	2000
Natural gas swaps*	19 mmcf/day	1.87	13	1998
U.S. dollar swaps	U.S.\$15	1.43	21	1998
	U.S.\$98	1.39	136	1999
	U.S.\$159	1.37	218	2000
	U.S.\$100	1.39	139	2001

* Average price for crude oil swaps is WTI per barrel at Cushing, Oklahoma.

Average price for natural gas swaps is dollars per thousand cubic feet.

(a) Average price and revenue hedged is in U.S. dollars.

Interest rate hedges

The company enters into interest rate and cross-currency interest rate swap contracts when there is an opportunity to lower the cost of borrowed funds. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and a financial institution. The cross-currency swap contracts involve an exchange of Canadian dollar interest payments and U.S. dollar interest payments between the company and a financial institution, and an exchange of Canadian and U.S. dollar principal amounts at the maturity date of the underlying

borrowing to which the swaps relate. The swap transactions are completely independent from and have no direct effect on the relationship between the company and its lenders. The differentials on the exchange of periodic interest payments are recognized in the accounts as an adjustment to interest expense.

The notional amounts of interest rate and cross-currency interest rate swap contracts outstanding at December 31, 1999 are detailed in note 8, Long-Term Borrowings.

Fair value of derivative financial instruments

The fair value of these hedging derivative financial instruments is the estimated amount, based on brokers' quotes, that the company would receive (pay) to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

(\$ millions)	1999	1998	1997
Crude oil swaps	(136)	77	40
U.S. dollar swaps	(1)	(108)	(9)
Natural gas swaps	—	—	(1)
Australian dollar forwards	—	—	(6)
Interest rate and cross-currency interest rate swaps	—	10	13
	(137)	(21)	37
Unrecognized gain exposed to credit risk as at December 31, 1999	2		

The company may be exposed to certain losses in the event that other parties to the financial instruments are unable to meet the terms of the contracts. The company's exposure is generally limited to those other parties holding contracts with net unrecognized gains at the reporting date. The company, however, minimizes this risk by entering into agreements only with highly rated financial institutions, and through regular management review of potential exposure to, and credit ratings of, such financial institutions.

16. RECENTLY ISSUED ACCOUNTING STANDARDS

In March 1999, the Accounting Standards Board of the Canadian Institute of Chartered Accountants (CICA) issued new recommendations for the recognition, measurement and disclosure of the cost of employee future benefits. The company will adopt the new recommendations, effective January 1, 2000, in a manner that produces recognized and unrecognized amounts for all of its benefit plans the same as those determined by the application of accounting principles generally accepted in the United States. Adoption will result in the recognition of a liability and an expense for all employee future benefits in the reporting period in which an employee has provided the service that gives rise to the benefits.

In December 1997, the Accounting Standards Board of the CICA issued new recommendations dealing with accounting for income taxes. This standard requires the use of the liability method for computing deferred income taxes. Under current rules, deferred income taxes are computed using the deferred method. The company will adopt the new recommendations effective January 1, 2000.

These new standards issued by the CICA serve to harmonize Canadian and U.S. generally accepted accounting principles in respect to employee future benefits and income taxes.

Quarterly Summary

(unaudited)

Financial Data	For the quarter ended					Total year	For the quarter ended					Total year	For the quarter ended					Total year
	Mar	June	Sept	Dec	Total year	1999	Mar	June	Sept	Dec	Total year	1998	Mar	June	Sept	Dec	Total year	1997
	31	30	30	31			31	30	30	31			31	30	30	31		
(\$ millions except per share amounts)	1999	1999	1999	1999	1999	1999	1998	1998	1998	1998	1998	1998	1997	1997	1997	1997	1997	1997
Revenues	469	564	639	715	2 387	2 387	543	498	531	498	2 070	2 070	571	483	535	565	2 154	2 154
Net earnings (loss)																		
Oil Sands	19	35	46	74	174	174	50	30	35	35	150	150	51	16	54	58	179	179
Exploration and Production	3	14	20	6	43	43	4	4	7	10	25	25	10	3	4	7	24	24
Sunoco	6	4	13	8	31	31	8	16	8	8	40	40	7	15	17	—	39	39
Corporate and eliminations	(13)	(17)	(5)	(13)	(48)	(48)	(12)	(5)	(1)	(9)	(27)	(27)	(8)	(6)	(12)	7	(19)	(19)
	15	36	74	75	200	200	50	45	49	44	188	188	60	28	63	72	223	223
Per common share																		
— net earnings	0.13	0.34	0.67	0.67	1.81	1.81	0.46	0.41	0.44	0.39	1.70	1.70	0.54	0.26	0.58	0.66	2.04	2.04
— net earnings attributable to common shareholders	0.12	0.27	0.61	0.61	1.61	1.61	0.46	0.41	0.44	0.39	1.70	1.70	0.54	0.26	0.58	0.66	2.04	2.04
— cash dividends	0.17	0.17	0.17	0.17	0.68	0.68	0.17	0.17	0.17	0.17	0.68	0.68	0.17	0.17	0.17	0.17	0.68	0.68
Cash flow provided from (used in) operations																		
Oil Sands	53	90	104	158	405	405	96	74	86	64	320	320	95	30	101	105	331	331
Exploration and Production	42	43	39	48	172	172	39	36	42	50	167	167	46	31	38	47	162	162
Sunoco	23	17	37	26	103	103	24	39	26	23	112	112	25	36	41	19	121	121
Corporate and eliminations	(25)	(21)	(33)	(10)	(89)	(89)	(15)	(11)	16	(9)	(19)	(19)	(17)	(16)	(19)	13	(39)	(39)
	93	129	147	222	591	591	144	138	170	128	580	580	149	81	161	184	575	575

Operating Data																				
	For the quarter ended					Total year	For the quarter ended					Total year	For the quarter ended					Total year		
	Mar	June	Sept	Dec	Mar		June	Sept	Dec	Mar	June		Sept	Dec						
	31	30	30	31	31	30	30	31	31	30	30	31	31	30	30	31				
(\$ millions except per share amounts)	1999	1999	1999	1999	1999	1998	1998	1998	1998	1998	1997	1997	1997	1997	1997					
Oil Sands																				
Production (a)	95.5	112.0	101.5	113.2	105.6	91.8	90.8	96.9	94.7	93.6	81.3	55.6	86.1	94.3	79.4					
Sales (a)																				
– light sweet crude oil	54.6	41.3	52.1	62.8	52.7	64.5	52.0	59.5	59.3	58.8	56.9	36.9	59.1	61.1	53.5					
– diesel	7.9	6.8	8.4	9.5	8.2	10.8	8.7	9.7	9.6	9.7	11.6	6.3	11.6	10.4	10.0					
– light sour crude oil	28.8	54.8	47.5	35.1	41.3	20.1	31.5	30.0	24.8	26.6	11.4	13.1	16.8	16.9	14.6					
	91.3	102.9	108.0	107.4	102.2	95.4	92.2	99.2	93.7	95.1	79.9	56.3	87.5	88.4	78.1					
Average sales price (b)																				
– light sweet crude oil	20.55	24.47	27.23	30.81	26.06	24.46	22.83	22.90	20.91	22.80	27.82	26.03	26.04	26.55	26.65					
– other (diesel and light sour crude oil)	19.18	19.60	21.45	25.91	21.48	22.69	19.75	21.65	20.89	21.16	28.46	24.78	25.35	24.58	25.74					
– total	20.00	21.57	24.24	28.77	23.84	23.89	21.49	22.40	20.90	22.18	28.01	25.60	25.82	25.92	26.36					
– total *	18.52	22.29	27.56	33.72	25.89	22.41	19.60	20.68	18.78	20.37	30.89	26.49	27.03	27.29	27.98					
Cash operating costs (1) (c)	12.20	10.60	12.05	10.85	11.40	10.95	11.10	11.05	12.75	11.50	12.50	17.75	11.70	11.80	13.00					
Total operating costs (2) (c)	15.25	14.00	15.00	14.80	14.75	13.05	13.95	14.35	13.55	13.75	15.15	19.50	14.70	14.40	15.55					
Exploration and Production																				
Gross production **																				
Conventional																				
– crude oil (a) ***	10.8	9.7	8.4	7.9	9.2	11.2	11.3	11.5	11.6	11.4	11.0	10.6	10.3	11.0	10.7					
– natural gas liquids (a)	4.7	4.1	4.1	4.0	4.2	5.3	5.1	4.8	4.6	4.9	5.4	4.2	4.9	5.3	5.0					
– natural gas (d)	229	225	231	219	226	258	241	247	244	247	239	235	238	248	240					
– total (e)	38.4	36.3	35.6	33.8	36.0	42.3	40.5	41.0	40.6	41.0	40.3	38.3	39.0	41.1	39.7					
Non-conventional																				
– crude oil (a) ***	1.3	1.2	1.0	1.3	1.2	1.0	1.4	1.1	1.1	1.2	—	0.6	0.8	1.0	0.6					
Total production (e)	39.7	37.5	36.6	35.1	37.2	43.3	41.9	42.1	41.7	42.2	40.3	38.9	39.8	42.1	40.3					
Average sales price																				
– crude oil – conventional (b)	18.48	20.48	20.55	25.21	20.94	21.27	19.50	20.49	19.35	20.14	23.85	22.58	22.14	22.42	22.75					
– crude oil – non-conventional (b)	9.87	13.55	21.46	20.89	16.27	3.48	5.36	9.59	8.46	6.67	—	13.67	12.52	12.54	12.83					
– total crude oil (b)	17.57	19.70	20.65	24.61	20.40	19.67	18.01	19.53	18.42	18.90	23.85	22.01	21.46	21.60	22.22					
– total crude oil (b) *	15.60	20.95	27.30	31.08	23.12	17.57	15.35	16.97	15.66	16.30	27.57	23.41	22.73	23.13	24.16					
– natural gas liquids (b)	11.88	16.70	22.81	27.12	19.32	18.70	14.77	13.06	13.64	15.13	26.47	19.77	20.19	22.65	22.45					
– natural gas (f)	2.18	2.15	2.48	2.96	2.44	1.75	1.83	1.90	2.33	1.95	2.28	1.54	1.65	2.21	1.93					
– natural gas (f) *	2.10	2.17	2.58	3.11	2.48	1.74	1.83	1.86	2.36	1.95	2.37	1.53	1.63	2.23	1.94					
Sunoco																				
Refined product sales (g) ****	13.1	14.1	13.9	14.2	13.8	13.7	13.8	14.0	13.8	13.8	14.1	13.8	13.8	15.1	14.2					
Natural gas sales (d)	93	86	87	90	89	89	88	83	92	88	—	—	—	54	14					
Margins – refining (3) (h)	3.4	3.3	4.8	4.3	4.0	3.8	4.7	3.9	3.8	4.1	4.4	5.2	5.5	3.5	4.6					
– retail (4) (h)	7.9	7.6	6.9	7.2	7.4	6.4	7.0	6.9	7.9	7.0	6.4	6.9	6.9	6.9	6.8					
Utilization of refining capacity (%)	97	93	100	92	95	96	99	98	102	99	97	96	101	95	97					

* Excludes the impact of hedging activities.

** Currently all E&P production is located in the Western Canada Sedimentary Basin.

*** Before deducting 1999 Alberta Crown royalty of 0.9 thousand barrels per day (1998 – 0.9 thousand barrels per day; 1997 – 1.0 thousand barrels per day).

**** Excludes sales through joint venture interests.

Definitions

(1) Cash operating costs – operating, selling and general expenses, crude oil and products purchases, taxes other than income taxes and overburden cash expenditures for the period.

(2) Total operating costs – cash and non-cash operating costs (total Oil Sands expenses less royalties in Schedules of Segmented Data on page 48).

(3) Refining margin – average wholesale unit price from all products minus average unit cost of crude oil.

(4) Retail margin – average street price of Sunoco branded retail gasoline minus refining gasoline price.

(a) thousands of barrels per day

(b) dollars per barrel

(c) dollars per barrel sold rounded to the nearest \$0.05

(d) millions of cubic feet per day

(e) BOE per day

(f) dollars per thousand cubic feet

(g) thousands of cubic metres per day

(h) cents per litre

Metric conversion:

Crude oil, refined products, etc.

Natural gas

1m³ (cubic metre) = approx. 6.29 barrels

1m³ (cubic metre) = approx. 35.49 cubic feet

Five-Year Financial Summary

(unaudited)

(\$ millions except for ratios)	1999	1998	1997	1996	1995
Revenues					
Oil Sands	889	768	751	766	676
Exploration and Production	306	290	302	264	191
Sunoco	1 779	1 533	1 673	1 638	1 516
Corporate and eliminations	(587)	(521)	(572)	(568)	(482)
	2 387	2 070	2 154	2 100	1 901
Net earnings (loss)					
Oil Sands	174	150	179	164	130
Exploration and Production	43	25	24	22	10
Sunoco	31	40	39	32	36
Corporate and eliminations	(48)	(27)	(19)	(31)	(25)
	200	188	223	187	151
Cash flow provided from (used in) operations					
Oil Sands	405	320	331	318	278
Exploration and Production	172	167	162	146	103
Sunoco	103	112	121	90	106
Corporate and eliminations	(89)	(19)	(39)	(63)	(92)
	591	580	575	491	395
Capital and exploration expenditures					
Oil Sands	1 057	507	491	321	193
Exploration and Production	200	242	240	187	201
Sunoco	42	60	54	55	38
Corporate	51	127	62	—	4
	1 350	936	847	563	436
Total assets	5 176	4 104	3 457	2 824	2 440
Capital employed*					
Debt					
Short-term borrowings	32	16	36	24	35
Current portion of long-term borrowings	1	1	6	6	6
Long-term borrowings	1 306	1 298	767	395	253
Shareholders' equity	2 142	1 519	1 401	1 247	1 127
	3 481	2 834	2 210	1 672	1 421
Less capitalized costs related to major projects in progress	(1 084)	(373)	(599)	(157)	(157)
	2 397	2 461	1 611	1 515	1 264
Ratios					
Per common share (dollars)					
– net earnings	1.81	1.70	2.04	1.71	1.38
– net earnings attributable to common shareholders	1.61	1.70	2.04	1.71	1.38
– cash dividends	0.68	0.68	0.68	0.64	0.57
– cash flow provided from operations	5.36	5.27	5.24	4.49	3.62
– cash flow provided from operations attributable to common shareholders	5.02	5.27	5.24	4.49	3.62
Return on capital employed (%) *	8.8	9.9	14.8	13.7	12.6
Return on shareholders' equity (%) *	10.9	12.9	16.9	15.8	13.9
Debt to debt plus shareholders' equity (%)	38.5	46.4	36.6	25.4	20.7
Debt to cash flow provided from operations (times)	2.3	2.2	1.4	0.9	0.7
Interest coverage – cash flow basis *	8.8	8.7	15.4	21.9	20.1

* Definitions:

Capital employed – see page 48.

Return on shareholders' equity – earnings as a percentage of average shareholders' equity. Average shareholders' equity is the aggregate of total shareholders' equity at the beginning and end of the year divided by two.

Interest coverage – cash flow basis – cash flow provided from operations before interest expense and income tax payments, divided by interest expense plus interest capitalized.

Supplemental Financial and Operating Information

(unaudited)

	1999	1998	1997	1996	1995
OIL SANDS					
Production (thousands of barrels per day)	105.6	93.6	79.4	77.6	76.0
Sales (thousands of barrels per day)					
Light sweet crude oil	52.7	58.8	53.5	56.5	57.3
Diesel	8.2	9.7	10.0	10.0	10.0
Light sour crude oil	41.3	26.6	14.6	11.5	8.3
	102.2	95.1	78.1	78.0	75.6
Average sales price (dollars per barrel)					
Light sweet crude oil	26.06	22.80	26.65	26.67	24.13
Other (diesel and light sour crude oil)	21.48	21.16	25.74	27.27	25.50
Total	23.84	22.18	26.36	26.84	24.46
Total*	25.89	20.37	27.98	29.32	24.28
Cash operating costs (dollars per barrel rounded to the nearest \$0.05)**	11.40	11.50	13.00	12.30	12.00
Total operating costs (dollars per barrel rounded to the nearest \$0.05)**	14.75	13.75	15.55	14.70	14.55
Other oil sands statistics					
Overburden removed (millions of cubic metres)	22.5	22.2	17.5	12.4	8.9
Oil sands mined (millions of tonnes)	72.9	62.4	54.1	51.1	49.7
Average bitumen content of oil sands mined (per cent by weight)	11.6	11.6	12.7	12.1	12.0
Average crude yield of oil sands mined (barrels per tonne)	.529	.547	.535	.556	.558

* Excludes the impact of hedging activities.

** See definitions on page 63.

Synthetic Crude Oil Gross Reserves*

(millions of barrels)	Proved	Probable	Total
December 31, 1995	178	—	178
December 31, 1996	147	—	147
Revisions	(11)	—	(11)
Additions	231	463	694
Production	(29)	—	(29)
December 31, 1997	338	463	801
Revisions	(2)	1	(1)
Production	(34)	—	(34)
December 31, 1998	302	464	766
Revisions**	(10)	(13)	(23)
Additions	222	1 577	1 799
Production	(38)	—	(38)
December 31, 1999	476	2 028	2 504

Gross proved reserves do not reflect deductions in respect of Crown and applicable sublease royalties. Under the Crown Royalty Agreement, the Crown royalty rate is dependent on deemed net revenues; therefore, calculations of the net reserves would vary depending upon assumed production rates, prices and operating and capital costs.

* In January 1997, the company received approval from the Alberta Energy and Utilities Board to mine its Steepbank leases. Reserve estimates are based upon a detailed geological assessment, including drilling and laboratory analysis. Estimates also reflect the integrated nature of the

operation, and therefore reflect on demonstrated productive capacity, upgrading yield, plans for increased output, operating life and regulatory constraints. Production from Steepbank leases commenced in the fourth quarter of 1998.

** A proposal submitted to the Alberta Energy and Utilities Board in 1998 requesting approval of a plan for establishing the final pit wall design of Leases 86 and 17 was approved in October, 1999. As a result, the recovery from these leases will be reduced by approximately 20 million barrels of synthetic crude oil. This reduction is reflected in the 1999 proved reserves net revisions of 10 million barrels.

Supplemental Financial and Operating Information

(unaudited)

	1999	1998	1997	1996	1995
EXPLORATION AND PRODUCTION					
Production					
CONVENTIONAL					
Crude oil (thousands of barrels per day)					
– gross	9.2	11.4	10.7	11.0	12.1
– net	7.5	9.4	8.6	8.7	9.5
Natural gas liquids (thousands of barrels per day)					
– gross	4.2	4.9	5.0	5.3	3.6
– net	3.0	3.7	3.5	3.8	2.5
Natural gas (millions of cubic feet per day)					
– gross	226	247	240	226	173
– net	170	195	199	185	139
Total (thousands of BOE* per day)					
– gross	36.0	41.0	39.7	38.9	33.0
– net	27.5	32.6	32.0	31.0	25.9
NON-CONVENTIONAL					
Crude oil (thousands of barrels per day)					
– gross	1.2	1.2	0.6	—	—
– net	1.2	1.2	0.6	—	—
TOTAL PRODUCTION (thousands of BOE* per day)					
– gross	37.2	42.2	40.3	38.9	33.0
– net	28.7	33.8	32.6	31.0	25.9
Average sales price					
Crude oil					
– conventional (dollars per barrel)	20.94	20.14	22.75	23.74	22.08
– non-conventional (dollars per barrel)	16.27	6.67	12.83	—	—
– total (dollars per barrel)	20.40	18.90	22.22	23.74	22.08
– total (dollars per barrel) **	23.12	16.30	24.16	26.84	21.90
Natural gas liquids (dollars per barrel)	19.32	15.13	22.45	21.31	16.28
Natural gas (dollars per thousand cubic feet)	2.44	1.95	1.93	1.50	1.14
Natural gas (dollars per thousand cubic feet) **	2.48	1.95	1.94	1.63	1.11
Undeveloped landholdings ***					
Oil and gas – western provinces (millions of acres)					
– gross	1.5	1.7	1.7	1.4	1.4
– net	1.2	1.3	1.3	1.1	0.9
Net wells drilled ****					
Conventional					
Exploratory – oil	1	2	7	3	2
– gas	5	10	10	8	11
– dry	13	18	25	21	17
Development – oil	2	15	26	22	16
– gas	4	16	10	15	12
– dry	1	8	4	6	15
Non-conventional development					
– oil	—	—	—	5	—
	26	69	82	80	73

* Barrel of oil equivalent – converts gas to oil on the approximate long-term economic equivalent basis that 10,000 cubic feet equals one barrel of oil.

** Excludes the impact of hedging activities.

*** Metric conversion: Landholdings – 1 hectare = approximately 2.5 acres.

**** Excludes interests in 5 net exploratory wells in progress at the end of 1999.

OIL AND GAS DATA

The following supplemental oil and gas disclosure is provided in accordance with the provisions of the United States Statement of Financial Accounting Standards (SFAS) No. 69. This statement requires disclosure about conventional oil and gas activities only, and therefore the company's oil sands

activities are excluded. Additional information required by SFAS No. 69 is included in the company's Form 40-F report, which is filed in the Electronic Data Gathering, Analysis and Retrieval (EDGAR) system of the U.S. Securities and Exchange Commission (SEC). This information can be accessed on the internet at www.freedgar.com.

RESERVES	Crude oil and natural gas liquids	Gross	Natural gas	Crude oil and natural gas liquids	Net	Natural gas
	(millions of barrels)		(billions of cubic feet)	(millions of barrels)		(billions of cubic feet)
Proved						
December 31, 1995	58		912	44		691
December 31, 1996	65		995	51		754
Revisions of previous estimates	1		11	1		36
Purchases of minerals in place	—		10	—		8
Extensions and discoveries	10		164	9		128
Production	(6)		(88)	(5)		(73)
Sales of minerals in place	—		(4)	—		(3)
December 31, 1997	70		1 088	56		850
Revisions of previous estimates	—		(16)	—		(30)
Purchases of minerals in place	—		—	—		—
Extensions and discoveries	6		232	5		177
Production	(6)		(90)	(5)		(69)
Sales of minerals in place	(1)		(17)	—		(13)
December 31, 1998	69		1 197	56		915
Revisions of previous estimates	(2)		(103)	(2)		(80)
Purchases of minerals in place	—		1	—		1
Extensions and discoveries	—		53	—		41
Production	(5)		(82)	(4)		(68)
Sales of minerals in place	(11)		(53)	(9)		(45)
December 31, 1999	51		1 013	41		764
Proved developed						
December 31, 1995	50		686	39		521
December 31, 1996	54		675	42		514
December 31, 1997	55		727	44		568
December 31, 1998	53		730	43		557
December 31, 1999	38		627	30		471
Probable						
December 31, 1995	22		374	17		282
December 31, 1996	23		380	19		294
December 31, 1997	25		389	19		306
December 31, 1998	24		472	19		359
December 31, 1999	20		428	15		322

1. Proved reserves are considered recoverable under current technology and existing economic conditions, from reservoirs that are evaluated on known drilling, geological, geophysical and engineering data.

Proved developed reserves are on production, or reserves that could be recovered from existing wells or facilities, if the company placed them on production.

Probable reserves are not considered recoverable under current technology and existing economic conditions, but analysis of drilling, geological, geophysical and engineering data suggests the likelihood of their existence and future recovery. Probable reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

2. Gross reserves are before deducting royalties. Net reserves are after deducting royalties. Royalties can vary depending upon factors such as prices, production volumes, timing of initial production and changes in legislation.

All reserves are located in Canada. There has been no major discovery or other favourable or adverse event which caused a significant change in estimated proved reserves since December 31, 1999. The company has no long-term supply agreements or contracts with governments or authorities in which it acts as producer nor does it have any interest in oil and gas operations accounted for by the equity method.

Supplemental Financial and Operating Information

(unaudited)

OIL AND GAS DATA (cont.)

Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes

(\$ millions)	1999	1998	1997
At December 31	749	797	678

	1999	1998	1997	1996	1995
SUNOCO					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline – retail*	4.1	4.1	3.8	3.8	4.2
– other	3.7	3.5	3.3	3.5	3.3
Jet fuel	1.1	1.0	1.2	1.1	1.1
Other	2.7	2.5	2.6	2.3	2.3
	11.6	11.1	10.9	10.7	10.9
Petrochemicals	0.7	0.7	0.7	0.9	0.8
Heating oils	0.4	0.6	1.0	0.7	0.7
Heavy fuel oils	0.5	0.7	0.7	0.6	0.6
Other	0.6	0.7	0.9	0.6	0.6
	13.8	13.8	14.2	13.5	13.6
Natural gas sales (millions of cubic feet per day)	89	88	14	—	—
Margins (cents per litre)					
Refining	4.0	4.1	4.6	4.4	5.0
Retail	7.4	7.0	6.8	5.7	5.8
Crude oil supply and refining					
Processed at Sarnia Refinery					
(thousands of cubic metres per day)	10.6	11.0	10.8	10.6	10.5
Utilization of refining capacity (%)	95	99	97	95	94
Retail outlets ** (number at year-end)	415	423	441	452	542
* Excludes sales through joint venture interests. ** Sunoco branded service stations, other private brands managed by Sunoco and Sunoco's interest in service stations managed through joint ventures. Outlets are located mainly in Ontario.					
EMPLOYEES (number at year-end)	2 796	2 659	2 439	2 324	2 353

Share Trading Information

(unaudited)

(stock trading symbol SU)	For the quarter ended				For the quarter ended			
	Mar 31 1999	June 30 1999	Sept 30 1999	Dec 31 1999	Mar 31 1998	June 30 1998	Sept 30 1998	Dec 31 1998
Share ownership								
Average number outstanding, weighted monthly (thousands) (1)	110 233	110 408	110 501	110 510	109 947	110 044	110 101	110 161
Share price (dollars) (2)								
Toronto Stock Exchange								
High	52.20	61.70	63.50	62.85	54.75	55.40	54.45	51.50
Low	39.60	48.15	55.90	52.00	40.50	45.50	42.65	43.20
Close	50.75	60.35	56.00	60.40	51.75	50.00	49.25	46.00
New York Stock Exchange – \$U.S.								
High	34.50	42.00	42.90	42.80	38.25	38.75	35.80	33.60
Low	26.30	32.25	38.00	35.25	28.75	31.25	27.80	28.00
Close	33.50	41.15	39.10	41.75	36.25	34.75	31.90	29.90
Shares traded (thousands)								
Toronto Stock Exchange	27 617	16 030	16 381	12 015	15 404	11 683	14 390	11 956
New York Stock Exchange	966	1 316	1 544	976	507	415	334	581
Per common share information (dollars)								
Net earnings	0.13	0.34	0.67	0.67	0.46	0.41	0.44	0.39
Net earnings attributable to common shareholders	0.12	0.27	0.61	0.61	0.46	0.41	0.44	0.39
Cash dividends	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17

(1) The company had approximately 1 228 holders of record of common shares as at January 31, 2000.

(2) The company's common shares are traded principally on the Toronto and New York stock exchanges.

Information for Security Holders Outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%.

The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

Corporate Directors and Officers

DIRECTORS

Brian A. Canfield

Point Roberts, Washington
President and
Chief Executive Officer
BCT. TELUS
Communications Inc.

John T. Ferguson

Edmonton, Alberta
Chairman
Princeton
Developments Ltd.
Chairman
TransAlta Corporation

Richard L. George

Calgary, Alberta
President and
Chief Executive Officer
Suncor Energy Inc.

Poul Hansen

Vancouver,
British Columbia
Chairman and
General Manager
Sperling Hansen
Associates Inc.

John R. Huff

Houston, Texas
Chairman and
Chief Executive Officer
Oceaneering
International, Inc.

Michael M. Koerner

Toronto, Ontario
President
Canada Overseas
Investments Limited

Robert W. Korthals

Toronto, Ontario
Corporate Director

M. Ann McCaig

Calgary, Alberta
President
VPI Investments Ltd.

Bill N. Rutherford

Berwyn, Pennsylvania
Retired Senior Vice President
Human Resources
and Administration
Sunoco Inc., formerly
Sun Company, Inc.

JR Shaw

Calgary, Alberta
Executive Chairman
of the Board
Shaw Communications Inc.

W. Robert Wyman

West Vancouver,
British Columbia
Chairman of the Board
Suncor Energy Inc.
Vice Chairman of the Board
Fletcher Challenge Canada
Limited

OFFICERS

W. Robert Wyman

Chairman of the Board

Richard L. George

President and
Chief Executive Officer

Michael W. O'Brien

Executive Vice President
Corporate Development
and Chief Financial Officer

M. (Mike) Ashar

Executive Vice President
Oil Sands

Barry D. Stewart

Executive Vice President
In-situ and International Oil

Sue Lee

Senior Vice President
Human Resources and
Communications

David W. Byler

Executive Vice President
Exploration and Production

Thomas L. Ryley

Executive Vice President
Sunoco

Terrence J. Hopwood

Vice President
General Counsel and
Secretary

J. Kenneth Alley

Vice President
Finance

Janice B. Odegaard

Assistant Secretary



1999 Annual Report Card

make changes to each year's annual report based on feedback from readers. Once again, we would appreciate your comments on how we might improve. Please take a few minutes to evaluate our report.

Suncor's report was easy to read and understand.

- | | |
|---|--|
| ☐ Strongly Agree | ☐ Disagree |
| ☐ Agree | ☐ Strongly Disagree |

The report contained all the information I needed to know.

- | | |
|---|--|
| ☐ Strongly Agree | ☐ Disagree |
| ☐ Agree | ☐ Strongly Disagree |

The report provided the right level of detail.

- | | |
|---|--|
| ☐ Strongly Agree | ☐ Disagree |
| ☐ Agree | ☐ Strongly Disagree |

After reading the annual report, what is your opinion of Suncor?

Next year's annual report could be improved by:

I would like to receive more information about Suncor:

(Please note: all the materials listed below, plus much more, are available on Suncor's website at www.suncor.com)

- | |
|---|
| ☐ Quarterly Report |
| ☐ Environmental Report |
| ☐ Suncor's Position on Global Climate Change |
| ☐ Dividend Reinvestment and Common Share Purchase Plan |
| ☐ Other _____ |

To receive these publications, you may contact Suncor at 1-800-558-9071 or fill in your name and address below:

Name: _____

Address: _____

☐ If you would like to have your name removed from Suncor's mailing list, please mark this box and fill in your address above.

I would prefer to read future reports:

- | | |
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CORPORATE COMMUNICATIONS
SUNCOR ENERGY INC
PO BOX 38 STN M
CALGARY AB T2P 9Z9



Suncor Energy is
a member of the
World Business
Council for
Sustainable
Development.

Stock Trading Symbols and Exchange Listings

Common shares (SU) listed on Toronto and New York exchanges. 9.05% Preferred Securities (SU.PR.A) listed on Toronto exchange. 9.125% Preferred Securities (SU.A) listed on New York exchange.

Dividends

Suncor's Board of Directors reviews its dividend policy from time to time, in light of changes that may occur in the company's financial position. In 1999, a dividend of \$0.68 per share was paid (\$0.17 quarterly).

Dividend Reinvestment and Common Share Purchase Plan

Suncor's Dividend Reinvestment and Common Share Purchase Plan provides an efficient and cost-effective way for shareholders to increase their investment in Suncor. The Plan enables shareholders to invest cash dividends in common shares or acquire additional shares through optional cash payments without payment of brokerage commissions, service charges or any other costs associated with administration of the Plan. To obtain additional information, please call Montreal Trust Company of Canada at 1-888-267-6555, and a brochure more fully describing the Plan will be forwarded to you.

Stock Transfer Agent and Registrar

Montreal Trust Company of Canada in Montreal, Toronto, Calgary, Edmonton, Vancouver; The Bank of Nova Scotia Trust Company of New York, N.Y.

Annual Meeting

The annual and special meeting of shareholders will be held at 10:30 a.m. EST on April 19, 2000 at Le Royal Meridien King Edward Hotel, Toronto, Ontario.

Corporate Office

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Internet

Visit Suncor's home page on the World Wide Web at:
www.suncor.com

To Obtain Annual, Quarterly & Environmental Reports

Telephone: 1-800-558-9071
Sometimes our shareholders receive more than one copy of our annual report in the mail because their shares are registered in different names or addresses. We make every effort to avoid duplication. If you receive, but do not require, more than one mailing for the same share ownership, call Montreal Trust at 1-888-267-6555 to make arrangements to combine your accounts.

We Care – The release of Suncor's third EH&S report in 1999.

Suncor published its third "We Care" report in 1999. It contains the latest information about Suncor's record of performance on its journey toward sustainable development. This printed publication is available upon request.
Call 1-800-558-9071 or access the complete document at Suncor's website: www.suncor.com



"At Suncor we continue to focus ourselves on the two things that we believe will maintain and build value for our stakeholders: getting the most from our existing businesses, and implementing our growth plans. And our growth plans become more sharply focused with each passing year. "

RICK GEORGE

President and Chief Executive Officer

SUNCOR ENERGY INC.

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Calgary, Alberta T2P 2V5

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E-mail: info@suncor.com
Website: www.suncor.com



Suncor is committed to working in an environmentally responsible manner. The paper for the narrative section of this report has been supplied from a sustainable forest program and manufactured using a 100% chlorine-free bleaching process that reduces air emissions. This process saves 634,986 pounds of emissions that would have been produced using a non-chlorine-free sheet. The financial section of the report contains 30% post-consumer fibre.

Please work with us to protect the environment and recycle this annual report.